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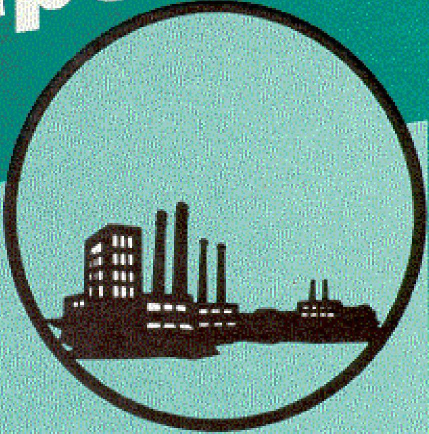
7th Clean Coal Technology Conference

21st Century Coal Utilization: Prospects for Economic Viability, Global Prosperity and a Cleaner Environment

PROCEEDINGS

Volume I

Policy Papers



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OPENING PLENARY SESSION

Without Clean Coal, Can the International Community Achieve Its Societal Goals?

AN INDUSTRY'S PLEDGE FOR THE 21ST CENTURY

General Richard Lawson
President and Chief Executive Officer
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Washington, DC, USA

Thank you, Secretary Gee, and thank you ladies and gentlemen.

Underlying this seventh Clean Coal Technology Conference is a gathering need for power producers to begin acting now so as not to falter or fail in delivering America's oncoming requirement for new power.

This requirement comes on amid parallel and corresponding transitions in the electric power industry, the coal industry, the economy, and public policy. Each transition influences the others in a tangle of cause and effect.

One of our early political leaders said that such times of transition – and I quote him directly – such times "...must always be (intervals) of uncertainty, confusion, error, and wild...fanaticism."

I suspect that to the many here who will be responsible for delivering the power of the future this sounds like – well, like a slow day at the office.

I was asked to examine what power producers might expect from the coal industry as the requirement for the 21st century comes on – to evaluate where and how coal fits in all of this.

Doing so means I must touch on deregulation of the electric power industry and a few questions of federal policy such as the environment and resources. This, in turn, may require me to encroach somewhat on the Secretary before me and on Linn Draper, of American Electric Power, after me; but I will try to keep the overlap to a minimum. Let's also think about what Americans expect and what America will require.

Federal projections on power requirements through 2020 include the following:

- Mid-range growth of almost 1.3 trillion kilowatt-hours;
- Loss of 270 billion kilowatt-hours in nuclear output brought on by early retirements brought on by competition;
- Loss of at least 27 billion kilowatt-hours of hydroelectric output;
- And an optimistic projection of a 59-billion-kilowatt-hour increase from other renewable forms such as wind, geothermal, biomass, and waste.

The sum of growth and retirements and adjustments points to a probable requirement for the capability to deliver an additional 1.6-to-1.7 trillion kilowatt-hours of power a year by 2020. For context this is:

- Almost twice the growth of the last 20 years;
- More than the present combined output of Japan and Germany, our chief international competitors – about 1.4 trillion;
- More than the present combined output of the European Union's largest economies – Germany, France, Italy, and the United Kingdom at 1.5 trillion;
- Almost 6 times last year's utility generation with natural gas;
- And only a little less than last year's utility generation with coal – 1.79 trillion kilowatt-hours.

This is an enormous amount of power.

It must come under conditions of competition and deregulation as set down in the National Energy Policy Act of 1992, enacted in consequence of the Persian Gulf War, which highlighted and underscored the requirements of energy security and economic security.

Competition and deregulation are meant to keep imported oil out of critical sectors of the economy, and to deliver America a stable power supply at the lowest possible cost.

Competition and deregulation will be fully implemented under federal and state legislation and regulation yet to be enacted.

Yet, whoever generates this power will be expected to make it happen without hiccup or hesitation – to have it in the right places at the right times in the right amounts at the right prices.

This will be expected whether the power supply comes from exempt wholesale generators, or independent power producers, or non-utility generators or traditional utility generators or some category of enterprise yet to be awarded its acronym.

There will be direct, price-driven competition at all levels – wholesale, retail, industrial, commercial and residential. Rules and practices will change. Profits and markets will no longer be guaranteed. Individual enterprises will be allowed to fail.

Nevertheless, be assured of this: Neither federal nor state policies will tolerate even for a short time frequent lapses or prolonged turbulence in delivery of the electric power requirement. It is the most required basic commodity in the U.S. economy today.

What can power producers expect of the coal industry?

For context let's turn to another period of transition in the economy and energy – one with a connection to this city of Knoxville. Knoxville was the site of the 1982 World's Fair, and the importance of energy was its theme.

The theme was of moment because the 1980s came on amid enduring economic dislocations. *The dislocations were rooted in failures of energy and economic policy, and they included high* inflation. There had been spikes in the price of oil, curtailments in the delivery of natural gas, and an incident in nuclear power that became a political cause.

Escalating electric-power prices were an economic irritant, a social agitation, and a political concern. The average retail price of electric power rose 250 percent between 1970 and 1982. The economy was stagnant. Unemployment was high.

In the years between 1982 and now the following came to pass:

- America's power requirement rose by 885 billion kilowatt-hours;
- The volume of power generated with coal rose by 50 percent;
- Coal delivered 587 billion kilowatt-hours of the new requirement – about 66 percent of growth, and more in total than the recent annual requirement of Germany;
- Coal-mining productivity increased an average 170 percent in a technological modernization of production that is on-going today;
- And so, coal producers became increasingly competitive with one another and with other fuel sources;
- The adjusted-for-inflation average price of coal delivered to the power plant was caused to fall by 53 percent;
- The adjusted-for-inflation average retail price of power fell by 30 percent;
- And, in today's best power plants, fuel and operating costs for a kilowatt-hour of electric power came to stand approximately as follows:
    - Natural-gas generation – 1.4 cents;
    - Nuclear generation – 1.35 cents;
    - And coal – 1.02 cents;
- And the share of power from coal rose from 51 percent to 57 percent.

In addition, electric-utility sulfur emissions were caused to decline during this time by 24 percent, and the emissions per-kilowatt-hour of coal output declined by 45 percent.

Improvements in the technology of production also influenced the recoverable reserve. In 1980 we thought we had a recoverable reserve of 200-to-220 billion tons. We've mined about 18 billion tons since.

Nevertheless, the estimate of reserves published this year is 275 billion tons, a one-third increase. Better recovery and other factors were at play.

In the first few years since the 1992 act became effective, America's power requirement has increased 8 percent, and coal-fired capacity delivered 60 percent of the added supply. The increase in annual coal-fired output is several billion kilowatt-hours larger than the full annual requirement of Sweden.

Generation with coal has trended steadily upward. Hydropower, nuclear, and natural gas all have fluctuated according to transient factors.

The average capacity-utilization rate of coal generation is rising steadily. Since 1995 the national average has increased 7 percent to a projected 70 percent this year; and other projections say it may reach 80 percent as the first wave of the new requirement continues to come on.

All of this happened without hiccup or hesitation in the power supply.

Coal performed for America and America's power producers where other forms – for whatever reasons – did not deliver on earlier promise and expectations.

Expect the coal producers to compete as fiercely in the future as they do in the present – to compete with one another, and with the other forms of generation. The coal industry is restructuring. The emphasis is on productivity, on modernization, and on the technologies of production; and the emphasis now is even stronger than it has been.

The industry is formally and firmly committed to the *Industries of the Future* initiative of the Department of Energy.

This program joins the mining industry with the national laboratories, with leading research universities, and with others in the early identification, timely development and orderly deployment of the technologies of the next century. Its purpose is to bring to bear on the concerns of today the practices and methods that were so successful in advancing the technologies of defense in what we used to call the Cold War.

The industry has established objectives that include:

- A doubling of output per miner;
- A halving of energy use in production;
- Dramatic innovation in production – less effect on air, water, and countryside plus advanced reclamation and remediation at higher efficiencies;
- Dramatic improvement in the techniques and capabilities of discovery;
- And, dramatic improvement in the recovery rate, for this will increase the size and extend the durability of the recoverable reserve.

Some specific considerations of increased productivity include the following:

- Improved robotics and autonomous mining systems;
- At-the-face beneficiation;

- And, *in situ* gasification – a means of developing reserves now beyond the reach of technology.

Such advances will quickly work their way into production and translate into competitiveness as they occur.

In the future, mines will be designed to accommodate technology, rather than the converse. We will seek improvements in miner health and safety and in the economics of production.

There will be fewer mines and larger mines. Surface mines of 25-to-50 million tons in annual production may be common, and deep mines of 5-to-10 million tons.

Some observers think the coal industry will come to resemble the oil industry in structure – 5-to-10 very large and very efficient companies delivering over half of production. The large companies and the smaller survivors will compete intensely.

What can power producers expect from the coal industry?

They can expect competition to the N^{th} power. They can expect coal to remain the low-cost fuel. They can expect reliability and availability in supply.

As power producers focus on costs and reliability, their concerns will tend to become the concerns of their fuel suppliers. There will be *de facto* partnerships with power producers and, probably, formal partnerships.

Some coal companies are becoming power brokers and traders – electric power. In time some may become energy and resource companies or partners in enterprises that supply an array of products.

The coal industry intends to support and participate in other efforts to impart shape and positive direction to the future.

And so, the coal industry was party to the legal proceedings that led to appellate court intervention in the Environmental Protection Agency's attempt to unsettle the onset of competition with wider restrictions on coal use – restrictions that went beyond both the authority of the Clean Air Act and the professional judgment of the agency's own scientific advisory panel.

We are in this fight to stay.

In addition, the coal industry is a party in full in this *Clean Coal Technology Program*:

- In full in technologies for improving coal as a fuel;
- In full in bringing on the lower-cost and more efficient means of controlling regulated emissions with retrofits and improved techniques;

- And in full in proving the technologies of advanced generation for repowered and greenfield capacity that in their higher efficiencies also address unregulated emissions – that is, carbon dioxide.

To the environmental and resource questions of federal interest: Every 1 percent increase in thermal efficiency causes a 3-to-4 percent reduction in CO_2 per unit of power production; and higher efficiencies extend the durability of the reserve by making a pound of coal deliver more power.

Expect such activity to continue.

Thus the coal industry is firmly committed to the *Vision 21* program of the Department of Energy and the following goals:

- 60 percent generating efficiency with coal as soon as possible;
- Carbon sequestration and near-zero emissions;
- And to developing as it becomes economic, and as soon as it becomes economic, the concept and component parts of coal-based energy complexes that deliver at low cost an array of essential material resources such as the following:
    - Electric power;
    - Natural gas, other fuels, and fuel additives;
    - Chemical products;
    - Higher levels of recovery from existing oil and gas fields;
    - And, through reuse of heat, 85 percent overall energy efficiency.

This brings us to the point of thinking about possible, probable and proposed federal policies. Not long ago, I was given a remarkable book that can help us do this – a book entitled *Energy in the Future*.

Energy in the Future is not remarkable for what it says:

- It enters into discussions of policy argument on why increased use may not be possible in electric power;
- And it postulates the possibility of a carbon dioxide driven change in climate.

Energy in the Future is remarkable for the perspective it offers. This book is 50 years old. The future was 50 years thence – that is, now. It is the commercial version of a report commissioned by the Atomic Energy Commission in 1949, another time of transition in America.

The book made the case for federal electrification policy that assigned 60 percent of the total energy requirement to the then-new concept of nuclear energy – what it called the "maximum plausible" contribution.

It rested in part on the argument that expense would consign coal to disuse – relatively high prices brought about by high production costs brought about by a combination of circumstances: First, the depletion of easy-to-get reserves; and, next, no change in the operations of production.

As recently as the time of the Knoxville energy fair in 1982 many projections still held that by the year 2000 about 35 percent of the power supply would come from nuclear generation – 35 percent of a much larger requirement than we now have. Yet today the outlook is for a decline of 45 percent by 2020 to 8 percent of supply.

However, from the time *Energy in the Future* was commissioned through 1997, the output of America's electric utilities increased by 2.7 trillion kilowatt-hours; and 58 percent of the growth came from coal-fired generation, which is not yet the maximum plausible contribution.

This happened because in that transition the efficiencies of coal production increased by almost 600 percent; the adjusted-for-inflation price of coal at the mine declined 40 percent; and the average thermal efficiency of coal-fired generation at least doubled.

I have two points in this, and neither of them is that the projections of *Energy in the Future* were wrong.

The first is that America requires diversity in the power supply for flexibility in any circumstance and all events. The atrophying of nuclear power can and ought to be reversed. There is no bad domestic energy. None should be ruled out by policy. None should excluded except by inability to compete.

However, a nuclear plant proposed this minute probably could not be on-line and contributing to the power requirement before 2020 – not without deep change in policies, these changes themselves a work of years and decades.

My other point is that performance will overcome the critics every time.

While some were saying it couldn't be done, while others were saying it shouldn't be done, while others were saying something else could do it with more style, the coal industry and those who relied on coal were doing it.

At the same time it must be recognized that there is in the story of nuclear power a caution for the only surviving sources of additional high-volume power generation – coal and natural gas.

Nuclear generation was forced to the side by factors that included:

- Big events outside the country;
- Missteps within the country;
- An inability to close with some underlying social and political challenges;
- And by an onslaught of campaigns – campaigns of persuasion and public opinion, of litigation, and of regulation.

These campaigns, in turn, raised three obstacles of pertinence to this discussion:

- First, concerns among the public;
- Next, uncertainty in financial markets, and resistance among investors;
- And, finally, the costs of nuclear generation.

The technologies of the *Clean Coal Program* and of *Vision 21* and of the *Industries* initiative will give power producers and coal producers the means to perform.

They give power producers and coal producers a way to come to grips with the underlying social and political questions as they perform; and to do so before the campaigns of speculation, regulation and litigation can raise them to the extremes of concern that forced nuclear generation to the side.

It's hard to argue waste and resource depletion to reasonable people if technological gains in production and of use have just combined to expand the durability of the recoverable reserve by two or three hundred billion tons and two or three centuries.

It's hard to convince reasonable people that America is the cause of the world's carbon dioxide concerns if average fleet efficiency has gone from 33 percent to 45 percent – if efficiency rates are working toward 60 percent and 85 percent and emissions toward zero.

America will require an enormous increment of new power over the next 20 years – more than the largest economies of Europe now require in combination; and also more than Japan and Germany combined.

Let's think for a moment about what Americans will expect from their electric power producers.

What will Americans find acceptable as the first decade of the new century grows older, as the unused capacity factors are used up, and as the requirement comes on to expand secure, reliable baseload output?

In the world today, the U.S. average of industrial power rates, with coal predominant, compares with others as follows:

- 37 percent lower than the European average;
- 49 percent lower than Germany, where subsidized coal and nuclear power are the mainstays;
- And 73 percent lower than Japan, where nuclear and imported liquid natural gas predominate.

Power is one of the comparative and competitive advantages American workers have in the global economy. It is one of the reasons they are the world's most productive.

Americans will not expect to forego either their standing or their advantage in the world economy.

Electric power is the indispensable ingredient in a modern economy, the single most versatile and valuable commodity. It is the feedstock of much activity and the genesis of more.

Almost every new form of economic activity or amusement or convenience requires electric power, and it improves the performance of most existing forms. It is the driving force of virtually all advanced technology.

An abundance of electric power is a condition requisite for a growth in the economy and for an improved personal standard of living; and its absence a predicate for decline in both.

A comparison of recent average international rates in dollars per thousand kilowatt-hours highlights and underscores the point as follows:

- Japan – $269 for household power and $185 for industrial power;
- Germany – $204 for households, $101 for industry;
- The European average – $137 for households, $79 for industry;
- And, the U.S. – $84 for households, $47 for industry.

Americans will not expect these margins to decline or fluctuate significantly to their detriment. Neither will their elected representatives, especially in election years.

What will Americans require?

They will require 1.6-to-1.7 trillion kilowatt-hours of power without hiccup or hesitation. They will require it in the right places at the right times in the right amounts at the right prices without exception or excuse.

Deliver it on other terms and everything either slows down or goes down.

Neither federal nor state policies or policymakers will tolerate even for a short time either frequent lapses or an inherent bias toward turbulence. Outbreaks of either could well flip all of power production quickly back into another period of transition.

What can power producers expect from the coal industry?

Expect competition. Expect reliability. Expect availability. Expect performance.

I urge you who will be responsible for delivering this increment of power to work this performance into your thinking now, if you have not already done so.

Performance prevails over the critics every time – over speculative criticisms and speculative promises.

Indeed, coal's promise for the 21st century is: Performance! Performance! Performance!

Thank you for your attendance and your attention.

A NEW POWER INDUSTRY TO MEET THE CHANGING DEMANDS OF THE MARKETS OF THE FUTURE

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ABSTRACT

American Electric Power has been a close partner with the coal industry for nearly a century. Throughout the AEP System, almost 90 percent of its power supply capacity of nearly 24,000 megawatts relies on coal-fired generation. When the pending AEP merger with the Central and South West Corporation of Dallas, Texas, is completed, the new AEP will be more fuel diverse but still predominantly dependent upon coal. The United States will be more diverse in its fuel sources for generating electricity in the future, but still heavily dependent on the coal-electricity partnership. There currently are four large-scale options for generating electricity: coal, nuclear, hydro, and fluid hydrocarbons -- oil or gas. Each has its challenges and limitations. Coal is plentiful and economical, but has significant environmental challenges.

This keynote presentation discusses the continuing development of clean coal technologies and their commercial viability as a critical pathway to the future. It outlines the need to reconcile air quality issues with economics as the electricity industry is undergoing dramatic change and the competitive marketplace continues to develop.

I. INTRODUCTION

Good morning.

It's a pleasure to take part in this important forum and comment on the continuation of the coal-electricity partnership into the 21st century.

We're in the stretch run to the new millennium, which seems to amplify our awareness of the future of our industries.

II. ENERGY IN THE FUTURE

I think we are also more conscious of the inherent risk in forecasting and predicting, but there's no big risk in observing that, while coal has great promise, it is being challenged.

Your program has promised I will talk about "A New Power Industry to Meet the Changing Demands of the Markets of the Future."

Clearly, the demands of new energy markets and attendant issues will require our creative ingenuity going forward.

The energy industry, especially electric power, without question is undergoing a thorough and dramatic transformation.

Restructuring and privatization are occurring on a global basis, and the pace of this activity seems likely to continue accelerating.

At the same time we are debating industry structure, there is intense interest in the fuels we use.

III. FUELS FOR THE FUTURE

Change is upon us, and I will suggest three "givens" I believe are in particular context of this conference and the future of the coal-electricity partnership:

1) Powering the future will require a diversified fuel mix.
2) Coal will continue in a prominent role in that mix.
3) The advancement of clean coal and related technologies will be more critical than ever going forward.

Our planning for the future must consider that there are four large-scale options for generating electricity: coal, nuclear, hydroelectric, and fluid hydrocarbons -- either oil or gas.

Each has its problems and limitations.

Nuclear has its detractors.

The ongoing, unresolved debate in the Congress and elsewhere of a storage solution for spent nuclear fuel has been a concern and frustration to the industry.

Hydro dam relicensing is an issue.

Solar, wind, and such renewable sources are interesting and getting much attention.

AEP is a participant, for example, in the Department of Energy's Million Solar Roofs initiative.

In Texas, our merger partner the Central and South West Corporation is involved with a wind project which, when fully operational, will have almost 75 megawatts of capacity.

But no one has figured how to widely deploy these intermittent energy supply options.

For U.S. electric utilities today, non-hydro renewables account for less than one percent of total generation.

Natural gas is the fuel of choice for new generation in the short term, and environmentally superior to coal.

Everyone who has taken a look at our industry out over 30 years projects that if coal and nuclear were phased out, three quarters of our nation's power-generating fuel might be natural gas.

This would seriously limit the competitive options in fuel choices and that would be a very big concern.

It could be crucial in the case of a major disruption similar to the oil crisis in the 1970s.

So for the future, a fuel diversity strategy in which advanced fuel technologies compete for efficiency, environmental benefit, and economy will be of paramount importance.

Such a strategy must seek to balance the right levels of gas, renewables, nuclear -- and coal.

IV. CHALLENGES TO COAL

It must do so in the face of a multitude of challenges to coal that will not go away and will undoubtedly intensify in the foreseeable future.

Powerful forces have identified coal as the enemy they will get rid of, if they can. They effectively command policy, media, and public attention.

Their arguments have an appeal that is often more emotion-driven than fact-based -- relying on the principle that perception is reality.

So the reality for its users and producers is that public perceptions of coal are not very good.

As one of the trade publications (*RCI Sourcebook* 6/99) put it, "when it comes to the environment and the public . . . passion kicks in at high voltage levels."

In other words, people are prone to believe what they are emotionally persuaded to believe.

This makes it difficult to persuade them that while protecting the environment is critical for the future, affordably and reliably providing electric energy is equally so.

These are not either/or. They are "both of the above."

At the end of the day, we will all need to be on the same side.

The most prominent concerns about coal seem to be currently on three broad fronts:

1) The issues of air quality -- urban and regional smog, or ozone, associated with nitrogen oxide emissions.
2) Fine particulates, acid rain, mercury, and regional haze, primarily associated with sulfur dioxide emissions.
3) The climate change questions of greenhouse gases, principally carbon dioxide, and global warming.

In the summer of '99, TRI has been added to these as another tricky perception issue for coal-burning electric utilities -- the Toxics Release Inventory they must now report, as required by the U.S. EPA.

The EPA and the Electric Power Research Institute have studied utilities' releases and determined that most pose extremely low risk to public health and the environment.

But the number of pounds of chemicals a leading coal generator like AEP must report are very large. When you burn millions of tons with concentrations of parts per million, you emit tons.

Helping people understand what the numbers do and do not mean is a very large challenge.

As for the ongoing NOx debate -- its genesis was in the regional squabbles over Midwest power plant emissions that northeastern states say are blowing hundreds of miles downwind and preventing them from meeting the ozone air quality standard.

New York State says it couldn't meet the ozone standard if all of its coal plants were shut down.

Coal-fired power plants are an attractive environmental target because they are an easier political target than other sources of emissions like the automobile.

The U.S. EPA listened to the northeastern states and ordered draconian emissions reductions of 85 percent from 1990 levels by 2003.

The agency rejected a plan from several midwestern states for a 65-percent cut that would allow the affected areas to meet air quality standards.

Now with the latest decisions and legal turns, the air quality rules, state implementation plans, and such, will likely be argued in the courts for another year or more.

We know we must assess the potential ramifications of the issues of particulates, acid rain, mercury, and regional haze to be ahead of the curve.

There is plenty of debate ahead on the questions of: What are the long-term health implications? What are the viable ways to address this issue?

While the Kyoto treaty is not in force at this time, AEP and other coal-based utilities are carefully reexamining their future fuel strategies.

V. INDUSTRY ENVIRONMENTAL INITIATIVES

It's important to emphasize that the electric industry, its coal partners, and others are not sitting back and waiting for any of these issues to gel or overtake them.

They are continuing to move ahead and do the right things as they have done for quite some time:

- Supporting and advancing the technology to cut power plant emissions.
- Promoting the ongoing development of advanced clean coal technologies and their commercial viability.
- Making environmental stewardship an integral part of their strategic objectives and business planning.

Last week we received the prestigious 1998 Edison Award which our AEP employees earned for their environmental activities and achievements.

The Edison Electric Institute and the award judges cited their "aggressive work to develop sustainable, environmentally responsible operations for coal-burning power facilities that meld bottom-line results with environmental stewardship."

Coal mine reclamation, wildlife habitat efforts, reforestation, carbon sequestration, pollution control, and energy efficiency initiatives all played into this recognition.

AEP has long been active in various areas of emissions reduction technology and advanced CCT development.

We have participated in CCT projects in conjunction with the DOE, and in our home state with the Ohio Coal Development Office.

At the AEP Cardinal Plant at Brilliant, Ohio, we're demonstrating the ability of SNCR or selective non-catalytic reduction technology as a cost-effective option for reducing NOx emissions in a generating unit as large as 600 megawatts.

Through the Electric Power Research Institute, AEP is taking part in an experimental test program at the Power Systems Development Facility near Birmingham, Alabama.

There, the development of improved, high-efficiency, coal-based combined cycle systems is under way.

We along with many of you are participants in the Coal Utilization Research Council, which seeks to maintain a dialogue with the DOE on the development of advanced CCTs.

I have had the privilege of working with many of you at the National Coal Council in its advisory and guidance role as requested by the Secretary of Energy on matters of coal, its marketing and use, and coal research.

AEP and other companies will of course comply with any new rules when they are ultimately finalized.

But again, they are not waiting for those rules to prompt their environmental protection and improvement initiatives.

It is extremely important that there be a sharp focus on carbon sequestration and sinks as options for reducing the atmospheric concentrations of carbon dioxide and other greenhouse gases, should national policies mandate emissions reductions.

And credit clearly is due the utility industry for leading all others in implementing voluntary, cost-effective actions to curb emissions of CO_2 and greenhouse gases.

I'll remind us all that since 1994, when the voluntary Climate Challenge program was forged between then-Energy Secretary Hazel O'Leary and the electric utility industry:

- Some 650 companies have pledged to reduce, avoid, or sequester more than 174 million metric tons of carbon dioxide-equivalent greenhouse gases.
- This is more than four times the emissions reductions that were originally pledged.
- About 80 percent of those reporting their reductions to the DOE under the 1992 Energy Policy Act have been electric utilities.
- This is a powerful argument in support of voluntary, flexible, cost-effective, comprehensive actions -- and in opposition to legally-binding targets and timetables.
- There is no question, since the most cost-effective actions already have been taken, that future voluntary reductions will be more difficult to achieve without incentives and the removal of governmental barriers to the changes.

If you couple voluntary emissions reductions with cost-effective, technologically feasible carbon sequestration and storage, you have expanded options for dealing with this issue.

Clearly, the momentum and desire for greenhouse gas emission reductions is going to continue.

When you take the one-two-three combination of new NOx and SO_2 regulations and the global movement to reduce CO_2 emissions, there is challenge enough to go around for electric utilities and our coal partners, energy researchers, and all of the best energy policy experts we can muster in both the public and private sectors.

The current environmental pressures on coal are unprecedented in their scope and intensity and they are not going to abate soon.

The task for all of us is to find the most responsible ways to respond to these pressures.

VI. THE COAL-ELECTRICITY PARTNERSHIP

At this millennial turnover time, if the past indeed is our teacher, we should remind ourselves that coal and electricity were already partnering the last time a new century was dawning.

In 1882, coal generated the power for Thomas Edison's first practical electric lighting system. There was quite a to-do as it illuminated one square mile of New York City.

Today's electric power system is the product and miracle of a century of technical achievement that has been awesome while enabling people to mostly take their electricity for granted.

Technology has shaped the structure of the electric utility industry, taking it from a local purveyor of an expensive product to an industry providing low-cost service in the developed world and hope to the developing world.

Technology has gotten this industry to where it is and will be critical to getting it where it must be.

The coal-electricity partnership is moving into a competitive marketplace driven by price, service, innovation, and customer choice.

Those who enjoy continuing success in the electricity, coal, and coal-related businesses will do so by finding the optimal ways to provide superior products and services to customers at the lowest possible cost.

Coal, more than ever before, will share in the destiny of the power generators it serves, based on the competitiveness of those power generators.

And again I will remind us that the roads to competition and environmental excellence are parallel.

It is not competition versus the environment. They will not collide.

Private accommodation and policy response to ensure this will be critical.

VII. RESPONSIBLY POWERING THE FUTURE

The viability of our society in the next century will rely on finding new and better ways to produce and deliver electric power.

I tried to make a couple of things especially clear in a few acceptance remarks at last week's Edison Award ceremony:

1) That our AEP attention to environmental stewardship was not just born yesterday. Our company has been at it for a long time now.
2) That we have no patent on these responsible environmental attitudes -- that this is a very conscientious industry.

That's why I am personally proud to be a part of it, and we at AEP are proud to be a part of it.

This is a business that has done much to respect and improve the environment, and does more every day.

Electric companies are vitally interested in preserving and improving the quality of life on this planet we all inhabit and want to leave it in even better shape for our children and grandchildren.

I have heard that Earth Day 2000 is some sort of big campaign target date for those most intent on taking coal out of the future power equation.

Every day is Earth Day for the electric utility industry and not just one per year in its care and concern for the environment.

Powering the future will require us to use all energy sources for long-term sustainability of the world's resources.

Fuel diversity will be important to preserving our country's national security and economic stability.

That fuel diversity should include the continuing development of renewable energy sources, expanded use of natural gas, and keeping the nuclear option open.

It will take the time and incentives for cleaner and more efficient coal-burning technologies to be developed and made available for power generation.

Coal will continue to produce the bulk of electricity consumed in the United States and much of the world as the future unfolds.

The big challenge for electric companies and their coal partners -- competing in a whole new marketplace -- will be to quickly respond to the changes, and efficiently and effectively power the 21st century in environmentally responsible ways.

VIII. CLOSE

Again, I appreciate the opportunity to share my thoughts in this key forum of policy and technical leaders as you examine critical economic, environmental, social, and market issues.

I urge you to have a productive meeting because the issues before you are so important to the future for all of us.

STRATEGIES FOR THE DEPLOYMENT OF CLEAN COAL TECHNOLOGIES

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ABSTRACT

We find ourselves at an interesting crossroads in the energy sector at the start of the 21st century. There are a series of processes, currently underway, which have changed the dynamic by which fuels and technologies are valued and how they might play a role in the first quarter of the new century. These processes are market reforms in developing and transitional countries, and fuel resource availability and increasing concern for climate change phenomena. The deployment of new, advanced clean coal technologies is further complicated by the fact that in the period 1996-2020 92% of all new coal-fired capacity is forecasted to be built outside of the United States. Market entry strategies, therefore must look for mechanisms to accommodate this. Unfortunately, there is little historic precedence for successful demonstration and deployment of new generation technologies outside the United States.

This paper explores the mechanisms developed by the President's Council of Advisors on Science and Technology (PCAST) Panel on International Cooperation in Energy Research, Development, Demonstration, and Deployment. Its conclusions underscore the need to put in place the collaborative mechanisms laid out in the PCAST report if meaningful deployment of clean coal technologies is to take place and if U.S. industry is to play a meaningful role.

I. CURRENT ISSUES

We find ourselves at an interesting crossroads in the energy sector at the start of the 21st century. There are a series of processes, currently underway, which have changed the dynamic by which fuels and technologies are valued and how they might play a role in the first quarter of the new century and beyond. These processes are market reforms in developing and transitional countries (including privatization and globalization of the electric power sector), fuel resource availability and increasing concern for climate change phenomena.

Market Reforms

The shift from centrally planned or state controlled utility systems to privatized utilities has lead to a variety of changes in this area. First this action has opened the market to private investors (including banks) which have focused their investments on more modular, standardized plants with lower capital costs. The availability of natural gas has made this approach the least cost option.

However, economic development and quality of life improvements for most of the world's population will require major expansions in the provision of energy services in the decades ahead. Most of the expected growth will take place offshore, especially in developing countries. Global energy and electricity demand are expected to increase by 78% and 92%, respectively, in the period from 1996 to 2020, but US markets are expected to account for only 9% and 12%, respectively, of these global increments (EIA, 1998). One estimate (PCAST 1999) puts the value of the new capital stock demanded globally between now and 2020 to produce this energy, including replacing retiring stock is very roughly $12 trillion or $500 billion per year (not including the value of energy end-use equipment sales).

However, the opening of power markets (at least to competition in generation) has had another effect, namely the diminishment of longer range R&D on new generation technologies (more on this later).

Fuel Resources and Climate Issues

In 1996 fossil fuels provided 86% of global commercial energy; under business-as-usual conditions, and this fraction is not expected to decline over the next two decades (EIA, 1998). There are trends for the future which can and will change the way in which they are used:

- Although domestic oil production is expected to decline 0.9 million barrels per day, 1996-2020, production at the global level is expected to increase from 72 to 116 million barrels per day resulting in a growing world dependence on the politically unstable Persian Gulf, whose share of world oil production is projected to grow from 26% to 41%, 1996-2020 (EIA, 1998),

- The developing countries with 75% of the world's population use only 20% of the gas available globally,

- Some 92% of the expected global increment in coal demand in the period from 1996 to 2020 is expected to be in developing countries, mostly in China (EIA, 1998).

- There is growing public health and environmental impacts of fossil-energy-derived air pollution, including growing concerns about chronic mortality impacts of small particle air pollution, and

- Climate-change implications of increasing CO_2 emissions from fossil fuel burning are projected to increase from 6.0 Gt C per year to 10.4 Gt C per year, 1996-2020 (EIA, 1998).

Even if more gas is found, developed and shipped to the developing world, it is clear that to meet the growing need for power globally, other fuels must be used. While most believe that renewables and nuclear power, along with energy efficiency, will reduce the need for fossil fuels from what they might otherwise have been, there will continue to be a strong global need for clean coal technologies. This need is shown in Figure 1.

But Figure 1 also shows the potential impact coal can have on carbon emissions if clean coal technologies are used. This is due to the fact that fossil energy technologies have been advancing rapidly in response to competitive challenges and tightening environmental norms, making fossil fuels both environmentally more acceptable and the energy services provided less costly—while providing moving targets against which renewables must eventually compete.

The question, then, is how do we bring about the introduction of clean coal technologies when the domestic market is expected to be essentially non-existent over the next one to two decades? To answer this, we need to look at the energy RD3 (Research, Development, Demonstration, and Deployment) process.

Table 1. Projection Of Coal Use and CO_2 Emissions From Coal[a]

Region	1996			2020			Coal use growth rate (%/y)
	Coal use (EJ/y)	Coal CO_2 emissions (Gt C/y)	Coal $_{CO2}$ emissions as % of global CO_2 emissions	Coal use (EJ/y)	Coal $_{CO2}$ emissions (Gt C/y)	Coal CO_2 emissions as % of global CO_2 emissions	
U.S.	22.0	0.52	9	27.0	0.66	6	0.9
Other Industrial	16.4	0.40	7	18.3	0.42	4	0.4
EE/FSU	13.7	0.33	6	12.7	0.30	3	- 0.3
China	29.6	0.68	11	82.7	1.93	19	4.4
India	6.3	0.16	3	11.3	0.29	3	2.5
Other Developing	9.8	0.25	4	13.2	0.35	3	1.2
World	97.9	2.34	39	165.0	3.95	38	2.2

[a] Reference EIA projection (EIA, 1998).

II. THE ENERGY RD3 PROCESS

Most of us are quite familiar and comfortable with the process of developing new coal based technologies and bringing them out of the laboratory, what I will call the traditional research and development (R&D) process. There is less definition and understanding with the follow-on steps of demonstrating these technologies and causing them to be deployed in commercial markets on a wide-spread basis.

The RD3 steps are tightly interconnected: R&D leads to innovative technologies for demonstration and deployment, while lessons from demonstration and deployment propagate backwards in the pipeline to guide targeted basic research and applied energy-technology R&D (PCAST 1997). The steps, moreover, entail not only technical but also financial and institutional dimensions. The financial dimension entails a web of public and private investment, with changes in level and form at each stage of the RD^3 process, including even, for small- to medium-scale technologies, the availability of retail finance so that end-users are able to purchase the technology. Institutionally, the pipeline involves public and private research laboratories, public-private technology demonstrations, mechanisms for publicly assisted buy-down of innovative-technology costs, and a variety of other arrangements.

For every technology and every geographic and economic setting, careful consideration must be given to the design of the combination of technical, financial, and institutional mechanisms that will ensure, at each step of the ERD^3 pipeline, the most effective use of public and private funds, the least possible public and private exposure to risk, the best use of competition to quickly drive costs down and performance up, the greatest transparency and smallest transaction costs, and the most effective public-/private-sector coordination as a technology moves through the pipeline. We turn now to some of the specific factors that must be taken into account at the different steps of that pipeline.

Research and Development

For a variety of reasons, the private sector under-invests in energy R&D relative to the public benefits that could be realized from such investments. This includes their inability to appropriate the benefits of their investment, the long term and/or high risk of the investment, and the low return on investments that address externalities such as air pollution that are not costed in the market. Consequently, the public sector has long been recognized as playing a vital role in supporting R&D, and it should continue to play this role...obviously with increasing private-sector participation as the technology moves towards a potentially marketable application or product. In the United States, the Department of Energy has been the principal public sponsor of energy R&D, with some support form the Environmental Protection Agency and others (PCAST 1997). A variety of mechanisms are used to encourage partnerships with the private sector within the United States (including, for instance, Cooperative Research and Development Agreements).

At the same time, the increasingly global character of the innovation environment makes it difficult even for nations to fully capture the benefits of investing in R&D. This impediment — on top of difficult budgetary constraints and a lack of appreciation for the importance of technological innovation for meeting the challenges — reduces the national incentive to invest in R&D. International cooperative R&D efforts can address this problem by sharing costs and risks and exploiting comparative advantages in innovation capacity, while minimizing competitive problems to some extent by virtue of the distance between R&D and commercial deployment.

Demonstration

The demonstration phase typically consists of building a series of energy-technology manufacturing or energy production/use facilities of increasing scale leading up to a plant of sufficient scale that it can ultimately be commercially viable. The private sector faces substantial difficulties in conducting such demonstrations. The time horizons for returns, although shorter than for R&D, are often still too long; the risks are or are perceived to be too high; the capital requirements can be large and sufficient capital thus difficult to obtain; the improved energy technologies may receive little or no return for reducing emissions or other externalities; and the pilot plants and even full-size commercial demonstration facilities cannot always compete against low-margin energy commodities of conventional kinds. These difficulties can be likened to rolling an increasingly heavy boulder up-hill. Thus, public support for demonstration is warranted as a means of realizing the public benefits associated with new, clean, and efficient energy technologies.

In the United States, public support for demonstration has been principally provided through DOE by several different measures, with varying success. Internationally, U.S. government support for overseas demonstrations may be warranted in cases where domestic demonstrations can not sufficiently test technologies against the conditions that characterize overseas markets, or where there is little or no current domestic market for the technology. Alternatively, and preferably, the U.S. government could support overseas demonstrations by providing the technical assistance needed to establish demonstration support facilities in nations undergoing energy-sector restructuring (see below).

Buy-Down

Once a technology has been demonstrated at a potentially commercially viable scale, there remains a long process of building a series of such systems to scale up equipment manufacturing facilities and/or generally to learn how to reduce manufacturing, system installation, and operations and maintenance costs to fully competitive levels. This process is described as driving costs down the "learning curve." To move a new technology into the market, its higher initial costs relative to competing products must be covered. As production volume increases, costs will be reduced until the technology is fully cost competitive. The process of paying the difference between the cost of a new technology and the cost of its competitors is known as early deployment "buy-down"—or simply buy-down—and is illustrated in Figure 1. The shaded area in Figure 1 indicates the "buydown" cost to make the product commercially competitive. Small modular technologies produced in factories often exhibit particularly strong learning curve cost reductions and are thus good candidates for using buydown strategies to lower their costs.

In some industries, such as the semiconductor industry, companies will often "forward price"—that is, initially sell their product below cost in order to rapidly increase their sales volume and drive their costs down the learning curve. This allows them to get prices down faster than their competitors and gain advantage. Because advanced semiconductors have greater capability than the previous generation, they also generally command higher prices, which reduces manufacturer losses when they initially sell below cost. This approach is more difficult in the energy sector, however. Because energy manufacturers are competing to sell commodity energy into a highly competitive market in which externalities are often not valued, they cannot rely on the advantage of being able to capture higher costs for the next-generation energy technologies. This can also mean that the overall buy-down costs are higher and will continue for longer periods of time, decreasing the probability that the private sector will find it profitable to engage in such buy-down activities.

Further, in contrast to the semiconductor industry, for energy technologies there are few or no high value niche market to sell into in order to reduce the overall buydown cost and these niche markets can be exceedingly difficult to tap. For example, an important high value niche market for small-scale renewable energy technologies is remote power applications. Increasingly, these applications are in developing countries but are individually small and hard to identify, and consequently also difficult to develop distribution and service networks for. When those hurdles are crossed, there is still the problem that potential buyers generally lack capital and access to credit.

Little has been done to address the buy-down problem. The Global Environmental Facility was created to help pay the incremental costs of technologies with significant public benefits in developing countries, and this has been largely done on a project-by-project basis with correspondingly high transaction costs. Paying the incremental cost of advanced clean energy technologies in a systematic manner so as to buy-down the cost of the technology towards commercially competitive levels has been started by the GEF. The U.S. has an interest—both with respect to leverage against global economic, security, and environmental problems and with respect to private-sector access to overseas markets—to ensure that these mechanisms and institutions for buy-down are implemented more broadly and systematically in restructured markets. These mechanisms and institutions, and the role the U.S. could play in establishing them, are discussed in more detail below.

Deployment

After a technology has proceeded through the R&D, demonstration, and buydown portions of the pipeline, and successfully maneuvered around the barriers and through the bottlenecks, it is ready for large-scale deployment. Barriers at this stage include convincing potential purchasers of the technology's advantages and overcoming their concerns about its risks, conducting feasibility studies, and building a distribution and service network, if needed. These generate high overhead costs for the manufacturer. In the case of small- to moderate-scale technologies, these overhead costs remain high even though the size of a project may be small—resulting in high overhead and transaction costs relative to the monetary value of the project. Within the United States, a variety of agencies provide support for overseas deployment activities, including USAID, Department of Commerce, the Export-Import Bank, the Trade and Development Agency, and the Overseas Private Investment Corporation, and to a lesser extent the Department of Energy and Environmental Protection Agency. The efforts of these agencies focus on supporting U.S. technology exports and supporting companies directly.

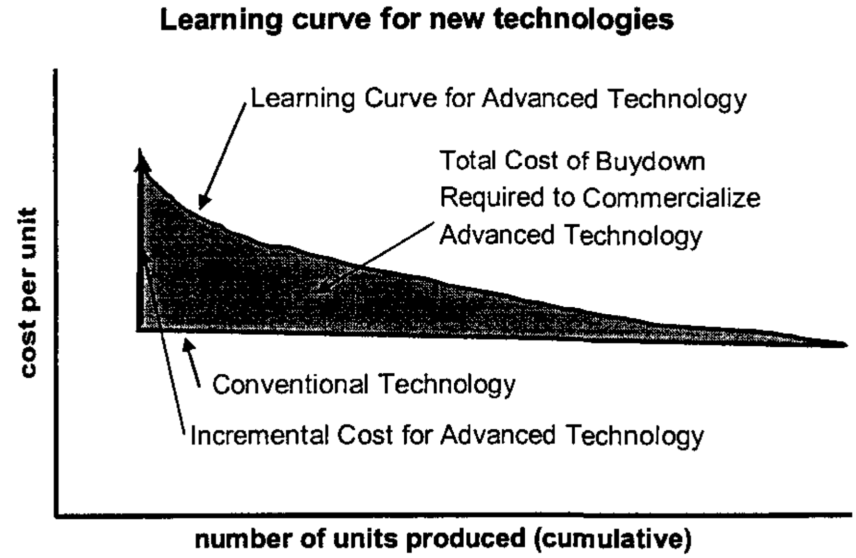


Figure 1: Learning Curve and Buydown for an Advanced Energy Technology.

III. UPGRADING PUBLIC-SECTOR PERFORMANCE

Even when energy sectors have been restructured to encourage maximum participation by the private sector in the RD^3 pipeline, significant gaps remain that must be "plugged" by the public sector (Figure 2). Frequently, in the United States and elsewhere, these public-sector plugs have been haphazardly applied, and, in cases where they have been applied, haven't provided tight seals to private-sector activities. Nonetheless, public-sector involvement is required to realize the full extent of the public goods that derive from energy innovation and avoid the full range of externalities that derive from energy supply. The deficiencies in the record to this point are an argument for improving that participation, but not eliminating it.

Developing a suitably strengthened RD^3 pipeline will require public-private partnerships that have the following characteristics (PCAST 1997):

- effective in quickly establishing reasonably large production and market demand levels for clean energy technologies, allowing companies to scale up production with some confidence that there will be a market in which to compete;

- efficient in driving down costs as cumulative production increases;

- minimally disruptive of existing energy-financial systems during the transition period;

- able — within available financial resources — to support a diversified portfolio of options;

- easily and transparently administered and requiring minimal administrative overheads; and
- temporary, with "sunset" provisions built into the commercialization incentive scheme *ab initio*, but long enough to catalyze the desired activity.

In addition, country partners in these activities should have the capacity and ability to assimilate new technologies into their energy infrastructure. Relevant questions in this connection are:

- Is the host country's energy sector positioned to understand and apply these technologies in a cost effective, market-driven manner?
- Does the host country have in place or otherwise available to it funding mechanisms to allow it to participate in the RD^3 process?
- Are the U.S. public and private sectors in the best position to leverage the opportunities to work cooperatively with various host countries?

The United States, as an international leader in promoting polices and practices that encourage market forces, has an opportunity to work with other countries to craft initiatives that would encourage competition as an alternative to failed centralized planning, while maintaining and strengthening the protection of public benefits. Measures to protect such benefits have been built into centrally planned and regulated systems over past decades in response to demonstrated public needs. Of particular interest here, these measures include (a) adequate energy R&D to provide the technological basis for responding to evolving understanding of public-benefits requirements and (b) support for demonstration and accelerated deployment of advanced energy-supply and energy-end-use technologies with public benefits that justify public investment in these steps. A window of opportunity exists in the next few years, while countries are reforming their energy sectors, to use the experiences of developing and industrial country leaders in energy sector reform to promote market-oriented restructuring that makes provision for these public benefits. This must be done before other, less desirable, practices are locked into place and lock out public-benefit considerations. The United States, which is also undergoing these changes, can itself benefit from the lessons learned in other countries further along in this process.

It is in the U.S. national interest to promote policies and practices that rely on competition, open markets, and international partnerships. U.S. companies will benefit through greater access to emerging markets. Other countries will benefit from access to the highest performance, cleanest, lowest cost technologies available worldwide and to market competition that can improve overall system performance and reduce and eliminate state subsidies and energy sector deficits. Those countries that become involved first are more likely to become regional leaders in developing and deploying these advanced energy technologies. Resulting collaborations will benefit from the technical and market strengths of the parties involved and the rigors of full market competition. The development of mechanisms to accelerate the development and adoption of advanced clean energy technologies will benefit the environment and reduce cost and risk.

Portfolio diversity can boost use of local resources and help reduce reliance on imported fossil fuels. These international partnerships offer win-win opportunities for all involved. Recommendations for U.S. involvement in energy-sector restructuring, capacity building, and finance are discussed in the next section.

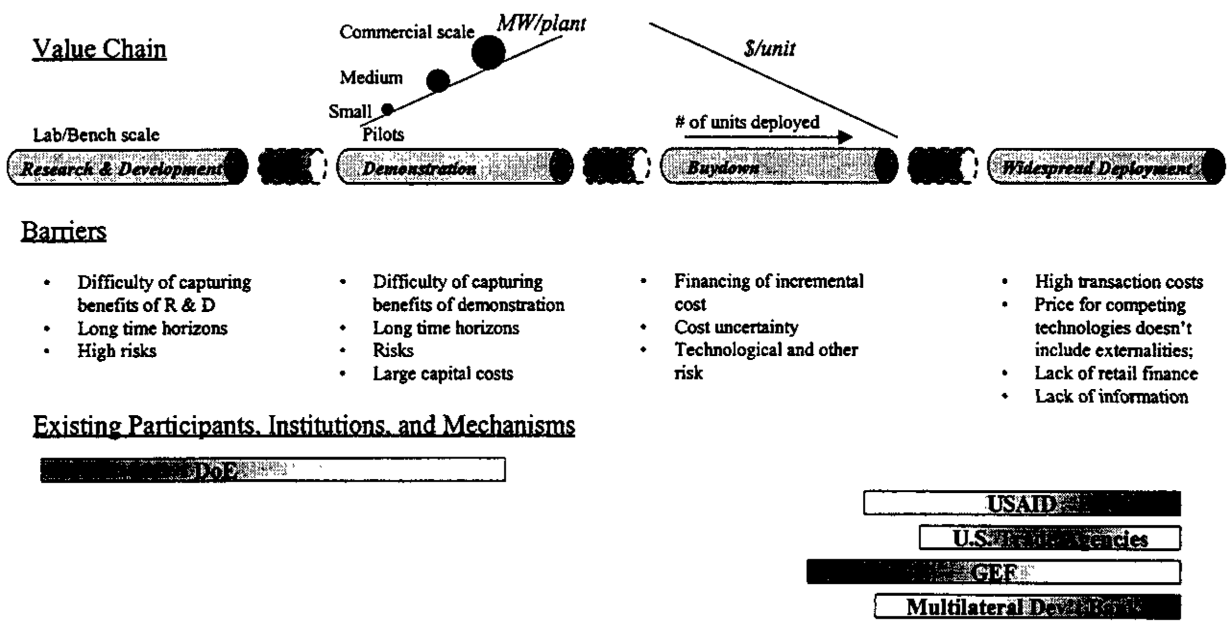


Figure 2: The RD3 Value Chain including Demonstration, Buy-Down and Deployment Processes, and the Gaps in Institutional Coverage in the RD3 pipeline.

IV. POLICY INITIATIVES

In what follows we describe four sets of measures for strengthening the foundations of international ERD^3 cooperation, shaped by the motivations and criteria described above.

-- The <u>capacity-building</u> cluster, designed to prepare the ground for rapid and sustainable energy-technology innovation, is recommended for funding at $20 million per year in FY2001, increasing to $40 million per year in FY2005. It contains as high-priority elements:

(1) increased support for existing regional centers for RD^3 of sustainable energy options and establishment of new sustainable energy centers in regions with significant need that cannot be met by other means; and

(2) expansion of existing – and development of new -- training programs for energy analysts and managers as well as a requirement that in-country technical and managerial training be a component of NGO technology demonstration and deployment projects supported by the U.S. government.

-- The energy-sector reform cluster is designed to support and shape energy-sector reform and restructuring – moving towards open competitive markets with improved financial performance – while retaining incentives for energy-technology innovation that addresses public goods and externalities. Recommended for funding at $20 million per year in FY2001, increasing to $40 million per year in FY2005, it has as high-priority elements:

(1) technical and policy advice – including through direct provision of personnel to the relevant partner-country organizations or through multilateral institutions -- to countries considering or undergoing energy-sector reform, with emphasis on (a) "getting prices right" through elimination of price controls and subsidies for conventional energy sources and through internalizing environmental costs, and (b) creating Public Benefits Funds (PBFs) to provide resources for advancing public benefits in the restructured energy sector – with funds raised through non-bypassable wires/pipes charges or by other means discussed below; and

(2) provision of assistance in establishing evolutionary regulatory frameworks for natural gas grids, beginning with simple pipeline systems linking large gas producers with large users and growing into grids serving a much wider range of producers and consumers.

-- The cluster on demonstration and cost buy-down mechanisms is designed to facilitate the demonstration, in foreign contexts, of advanced energy technologies with significant public benefits and to provide the means to "buy down" to competitive levels the costs of technologies in this category that have learning-curve characteristics making this practical. Recommended for funding at $40 million per year in FY2001, increasing to $80 million per year in FY2005, it has as high-priority elements:

(1) provision of assistance in establishing of a Demonstration Support Facility (DSF), preferably at the Global Environment Facility (GEF), to provide a framework for clean-energy demonstration projects that would attract support from the private sector as well as from various public-sector sources (including the GEF and PBFs and government grants in host countries);

(2) awarding of energy-production tax credits to U.S. firms participating in demonstration projects that are carried out under the DSF and that meet approved criteria (including being formulated so as not to conflict with U.S. opposition to tied aid); and

(3) provision of assistance in establishing of a Clean Energy Technology Obligation (CETO), preferably at the GEF, that would use competitive instruments to "buy down" the prices of targeted innovative technologies with incremental cost support provided by the GEF and by the host country through PBFs or direct government grants.

-- The financing cluster, aimed at overcoming financial barriers to deployment of small-scale clean and efficient energy technologies in transition and developing economies, is recommended for funding at $40 million per year in FY2001, increasing to $80 million per year in FY2005. Its high-priority elements are:

(1) measures to encourage increased financing for clean and efficient energy technologies from the Multilateral Development Banks (MDBs), including (1) establishing or expanding "trust funds", through the relevant U.S. agencies (such as DOE, USAID, and the U.S. Trade and Development Agency), which the MDBs can draw upon to support agency-approved technical assistance for project planning work to overcome barriers to obtaining financing and (ii) developing contingency plans and mechanisms for reinforcing, if necessary, the transition in World Bank and other MDB energy-project funding away from conventional energy technologies in favor of clean energy technologies (which is being driven by the ability of reformed energy markets to attract private capital for conventional technologies and the desirability of not distorting these markets with publicly supported MDB funds); and

(2) additional measures implemented by U.S. agencies to facilitate market-based finance of clean and efficient energy technologies, including creating a fund administered by the Overseas Private Investment Corporation (OPIC) to provide partial loan guarantees for these types of projects (to be phased out as the MDBs complete the transition to supporting clean energy technologies and advancing other public benefits).

These various initiatives are listed in Table 2.

Table 2: Representative Mechanisms for Incorporating Public Benefits

Mechanism	Description/Discussion	U.S. Action
Energy-Sector Reform	Shift to commercial rates, private energy firms, unbundle energy sectors, introduce wholesale/retail competition. Reform must include establishment of mechanisms or institutions that can provide public benefits associated with RD&D and other supports for technology innovation, costing externalities, portfolio diversity, equity, others.	Technical advice Leveraging activities of multi-lateral development banks
Public Benefits Fund	Established as part of restructuring through a nonbypassable wires/pipes charge, as done by Brazil (Box 3-xx), or by other mechanisms. It could be augmented by a debt for public benefits swap. Funds could be used for RD&D, capacity building, IRP, DSM, incremental cost buydown, rural concessions, or equity for the poor. A Public Benefits Fund needs to either establish competition or a rigorous budgeting process for use of the funds to ensure their effective use.	Technical advice (part of this initiative)
Debt for Public Benefits Fund Swap	For highly or moderately indebted nations, a portion of debt payment under debt relief could be directed towards support of the Public Benefits Fund, with agreement that other mechanisms would be used to continue Fund support after the debt was forgiven.	Debt relief (see initiative below)
Demonstration Support Facility	Establishment of facilities to promote in-country demonstration. Funded through GEF or Public Benefit Funds (1st best option) or directly through U.S. Agencies.	Technical advice Direct financial support (see initiative below)
Portfolio Diversity	To reduce system vulnerability to a supply disruption, appropriate fractions of the system could be specified for different resources and technologies. Could combine with the Clean Energy Technology Obligation to provide needed diversity.	Technical advice for Clean Energy Technology Obligation (see initiative below)

Clean Energy Technology Obligation	Conduct sequential competitive auctions for purchases of a particular technology class to allow manufacturing scaleup/volume production and buy the technology down the learning curve in a systematic, competitive manner. Incremental costs could be paid by GEF (1st best) or other multilateral/bilateral assistance (2nd best).	Technical advice Encouragement of GEF participation Direct financial support (see initiative below)
Integrated Resource Planning	Conduct analytical work to identify the mix of energy supply/demand resources to meet energy service needs at the lowest cost. In particular, this identifies underutilized energy efficient technologies.	See box 3-YY
Demand Side Management	Implement mechanisms and supports to lower market barriers to the use of cost-effective energy efficient technologies. Some of these barriers are described in Chapter 4.	See box 3-YY
Externality Costing or Controls	Externality costing through technology/fuel taxes, feebates, cap and trade systems, or other approaches to incorporate externalities in energy decision-making	Technical advice
Rural Energy Concessions	Facilitate the provision of rural energy services through competitive auctions of rural concessions, with Public Benefits Fund support of certain incremental costs and/or lifeline minimum service support.	Technical advice See box 3-ZZ on Argentinian concessions

In the PCAST 1999 report there also is a discussion on the use of a mechanism based on successes such as the U.S. SO2 allowance program. U.S. assistance and expertise could be particularly valuable in helping to establish and implement emissions monitoring and verification programs. In addition, U.S. specialists could assist with implementation of more conventional emissions standards programs, including efforts to establish output-based emissions standards (i.e., grams per kWh output rather than per MJ of fuel input). This approach would encourage efficiency improvements in power generation. In all of these efforts, particular emphasis should be devoted to encouraging and supporting policies that will speed up the introduction of inherently clean energy technologies.

In all cases (GEF, DSFs, U.S. government funding), targets should be established for deployment of an approved set of technologies covering energy efficiency/conservation, renewable/distributed energy resources, and larger "central station" technologies (which use indigenous resources in advanced, clean, applications), and bids for these projects should be solicited

Demonstration Support Facility

Increased demonstration of emerging technologies are required in order to expand the portfolio of technologies available to combat the economic and environmental problems associated with more conventional and less diverse energy supplies. Support for overseas demonstrations would ideally come from existing international institutions, such as the Global Environmental Facility (GEF). The GEF, however, has only funded one such project— the biomass integrated gasifier/combined cycle power project in the Northeast of Brazil. (Note that this demo will have multiple sources of investment support, including equity contributions from the private sector partners, World Bank loan, plus GEF grant to cover the incremental cost associated with the first-of-a-kind activity.)

The GEF has identified two categories of projects that qualify for 'incremental cost' funding. The first category involves technologies that are apparently fully cost-effective but whose deployment in the market is inhibited by high transaction costs and other institutional barriers. The second category involves new technologies that offer the potential for large GHG emissions reduction, are not yet cost-effective, but have good prospects for becoming cost-effective with accumulating experience. U. S. participation in this process should include:

- Establishment of overseas Demonstration Support Facilities: In the absence of an increase in demonstration activities through GEF, the U.S. government should provide technical advice to enable the establishment of domestically supported Demonstration Support Facilities in developing and transition countries undergoing energy-sector restructuring.

- Tax Credits: The U.S. government should award production (not investment) tax credits to U.S. firms participating in GEF- or DSF-sponsored demonstration projects. To qualify for the tax credits, Treasury must approve of the qualifying-technology and team criteria established for the DSF, and the project must meet other relevant U.S. Treasury criteria as well.

- Expansion of Domestic Support for International Demonstration: If the efforts of the GEF and overseas DSF's is insufficient to allow reasonable U.S.-firm participation in international demonstration projects, the U.S. government should consider expanding support for such activities through increased DOE and AID funding. Domestically supported international demonstrations should, however, be limited to either those technologies that have already been demonstrated in the U.S., but which must be reshaped to conform to developing or transition country conditions, or technologies for which there is no significant market in the U.S. (e.g., small-scale (< 500 kW) bio-power technologies).

The Clean Energy Technology Obligation

The most serious gap in the innovation pipeline (Figure 2) is the lack of a mechanism to buy down the cost of an innovative clean energy technology to competitive market levels. Mechanisms for technology buydown should and can be incorporated in the reformed and restructured energy sector.

In some industrialized countries where energy sector restructuring has or is taking place this challenge is being addressed by creating, in ways that are consistent with the general principles of restructuring, small guaranteed markets to help launch new energy technologies in the market. In these programs, prospective providers of qualifying energy technologies compete for shares of these markets. Examples of such programs are the Renewables Non-Fossil Fuel Obligation

(NFFO) in the United Kingdom and the proposed Renewable Portfolio Standard (RPS) in the United States.

The IERD[3] Panel proposes as a key element in energy sector reforms in the host developing or transition country a Clean Energy Technology Obligation (CETO) for accelerating deployment of promising new commercially-ready clean energy technologies targeted for deployment in partnership with the U.S. and/or other industrialized country partners, when the prices for these technologies are above market-clearing levels. The CETO would use competitive instruments to launch in the market over a specified period of time (~ 5-10 years) specified capacities for those technologies targeted for deployment. CETO competitions would be organized by setting target prices and guaranteeing markets at these prices sufficiently large that manufacturers will expand production capacity to levels where economies of manufacturing scale can be realized. Markets offering high value for energy would be identified to minimize the subsidies needed for price buy-downs.

CETO competitions could be organized in various ways. If modeled after the NFFO, the CETO would involve a series of auctions to buy down the prices of specified quantities of targeted technologies as shown in Figure 3

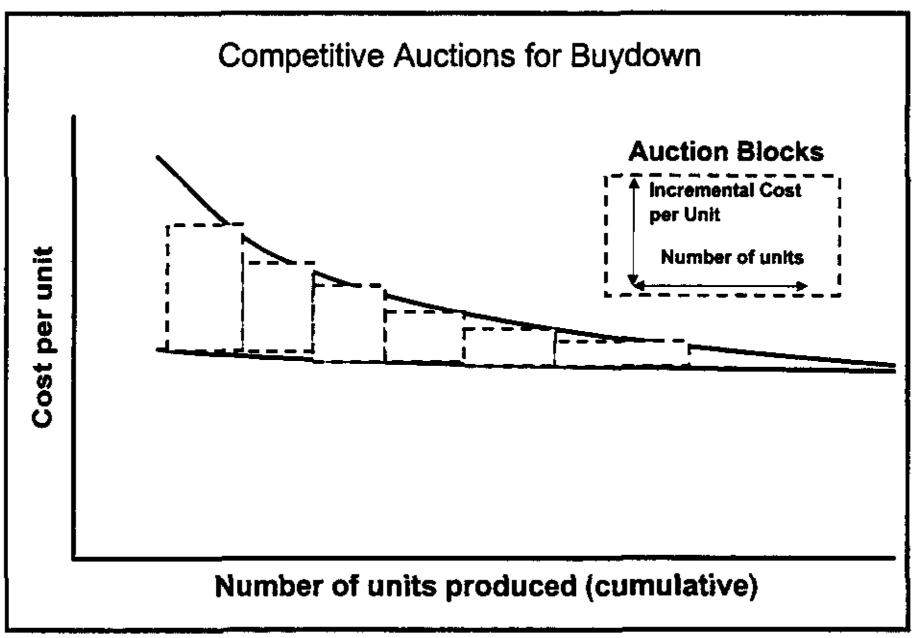


Figure 3: Competitive Auction Buy-Downs

The CETO should be limited to those technologies that offer major environmental benefits, have steep learning curves, and have good prospects for becoming widely competitive in the not too distant future under market conditions after subsidies are removed. Two concerns that warrant close scrutiny in designing a CETO: (*i*) the need to minimize the risks of "picking winners," and (*ii*) the need to focus resources in favorable theaters for innovation.

The "picking winners" concern can dealt with in part by designing a CETO that promotes a diversified portfolio of technologies, with limits on the total subsidy available for any particular technology. In addition, the portfolio mix could be adjusted over time to eliminate support for those technologies for which experience in the price buy-down process shows lack of promise for continuing cost reduction.

CETO competitions should be carried out where the prospects for success in the innovation process are high. Because technology successfully launched in the market in one region will often subsequently diffuse to other regions, favorable conditions for CETO-like activity are needed only somewhere in order to establish technologies in the market.

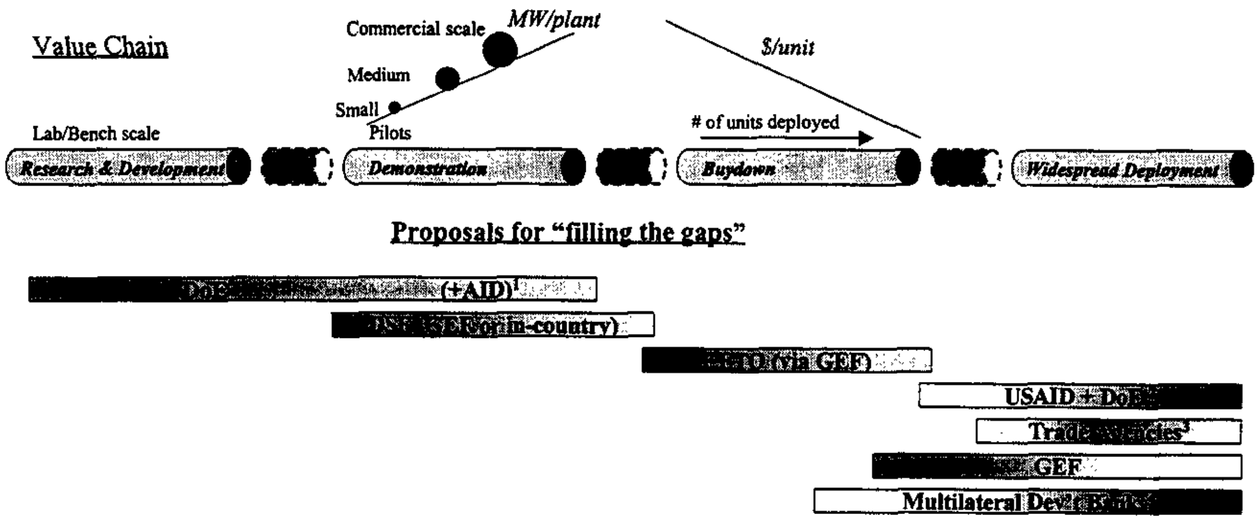
CETO competitions could be organized either by multilateral agencies or by the U.S. in partnership with the host country. The World Bank, the IFC, and the GEF could form a strong partnership for organizing CETO competitions, using GEF resources as needed to make contributions to pay for incremental costs. U.S. firms partnering with firms in the host country would prepare candidate projects for these competitions; some candidate projects for CETO might arise as a result of demonstration projects carried out under demonstration support facilities.

There are two major advantages of engaging the World Bank, IFC, and GEF as the lead organizing team for CETO competitions. First, the GEF, as the financial instrument for implementing the Framework Convention on Climate Change, is able, under its Operational Program No. 7. Second, engaging the World Bank, IFC, and GEF in this manner for promoting energy technology innovation would help advance the U.S. goal of maximizing the use of market forces in choosing the most promising CETs in the technology transfer process, because these agencies do not allow the use of tied aid (which greatly restricts the role of market forces in technology transfer) in sponsored projects.

If the World Bank, IFC, and GEF could not be so engaged, the United States could assume the responsibility for organizing CETO competitions with its host country partner.

Filling the Gaps

The above initiatives, together with increasing support from the Trade Agencies for advanced clean energy technologies—a trend that this Panel strongly endorses, can plug the gaps in the innovation pipeline and establish a strong environment for market-driven advanced clean energy technology development and deployment. This is shown in Figure 4, where the gaps have now been filled in with the mechanisms described in these initiatives.



(1) Through possible increased funding for demonstration (see Demonstration Initiative)
(2) Through increased funding of feasibility studies (see Finance Initiative)
(3) Loan guarantees through OPIC; technical assistance and feasibility studies through USTDA (see Finance Initiative)
(4) Taking over" some GEF activities, increased technical assistance, increased support for clean and efficient energy technologies (see Multi-lateral Development Bank recommendation)

Figure 4: The RD3 Value Chain with the "Gaps" Filled In.

V. CLEAN COAL AND THE NEW PARADYGM

What does this mean for Coal? Coal is an abundant but "dirty" fossil fuel. In the coming decades most of the expansion in coal use is expected to be in developing countries—especially China as shown in Table 1. If a business as usual scenario is followed in these countries there will be increasingly severe local and regional air pollution problems, and major increases in CO_2 emissions.

The US ERD^3 activity relating to coal should be oriented to serving the market needs of developing countries, in ways that are consistent with Vision 21. Vision 21 is a new Fossil Energy initiative at DOE (PCAST 1997, DOE, 1998). One long-term goal is to produce electricity from coal, at high efficiency and with near-zero greenhouse gas and air pollutant emissions—at a cost that is less than that for today's state-of-the art pulverized coal power plant. Vision 21 plants might also co-produce electricity and hydrogen with near-zero emissions, and they might use a variety of carbonaceous feedstocks in addition to coal—e.g., natural gas, petroleum residuals, biomass, and/or municipal solid waste. Bringing Vision 21 technologies to market would require considerable innovation, but it is projected that such technologies might capture 50% of the U.S. coal power market by 2011-2015, if they were pursued with an aggressive ERD^3 program.

A common feature of Vision 21 plants that would ultimately have zero or near-zero CO_2 emissions is that the processing of the primary carbonaceous feedstock would begin with syngas production. In the coal processing, *the key enabling technology* that leads to syngas production is oxygen-blown gasification. Gasification makes it possible to extract much of coal's energy as hydrogen, while producing a byproduct stream of relatively pure CO_2 that could be sequestered (e.g., in various geological reservoirs). Moreover, air pollution emissions would also be reduced to near zero levels if hydrogen were to come into wide use.

Advanced technologies for making hydrogen from coal via gasification might prove to be attractive ways to produce hydrogen if there were major energy markets for hydrogen—which would be the case, for example, if fuel cells could be developed and commercialized for both transportation and stationary power markets.

At present there are no energy markets for hydrogen. However, for the near term, oxygen-blown gasification technology could be employed to provide energy from coal with extremely low levels of local and regional air pollutants, along with modest reductions in CO_2 emissions as a result of efficiency improvements that are made possible by use this technology. Thus near-term "clean-coal" technologies based on oxygen-blown gasification are consistent with a transition to Vision 21 plants.

One near-term application is coal-integrated gasification/combined cycle (IGCC) power generation, which could provide electricity with air pollutant emissions as low as from natural gas combined cycle plants. However, although coal IGCC technology is commercially ready, it is not yet cost-competitive with conventional coal steam-electric technology in China and other developing countries.

One promising approach for buying down the cost of oxygen-blown gasification technologies is to promote applications in energy systems that co-produce electricity + industrial process heat (CHP), or fluid fuels + electricity, or fluid fuels + electricity + industrial process heat (e.g., using liquid phase reactors to produce these fluid fuels from synthesis gas via once-through processes—in cogeneration or trigeneration configurations similar to those described above using natural gas as feedstock). Such energy co-production systems offer as benefits low levels of air pollution, and significant cost reductions, energy savings and reduced CO_2 emissions relative to systems that produce these products separately. These systems might often be cost-competitive where coal IGCC technology producing only electricity is not.

Another promising approach would be to employ oxygen-blown gasifiers with low- or negative-cost feedstocks (e.g., petroleum coke rather than coal) as a near-term strategy for expanding market applications of gasification technology and thereby helping buy down technology prices. Such co-production strategies or strategies based on gasification of low-quality feedstocks might be evolved from ongoing activities in the petroleum refining and chemical industries. In China, for example, modern oxygen-blown gasifiers are already being deployed in the chemical industry for the production of ammonia and other chemicals.

If hydrogen were to come into wide use it might be feasible for fossil fuels to continue to have large roles in the global energy economy, even in a greenhouse gas emissions-constrained world. This is because the least costly way to make hydrogen is from fossil fuels, and the CO_2 separated out in hydrogen manufacture can be sequestered in isolation from the atmosphere. Extracting the fossil energy in the form of hydrogen makes it feasible to dispose of the CO_2 at relatively low incremental cost (in contrast to the relatively high cost of disposing of CO_2 recovered from the stack gases of conventional fossil fuel power plants). Even taking into account the added cost of CO_2 sequestration, the cost of making hydrogen this way would typically be much less than the cost of hydrogen produced electrolytically.

The fossil-fuel decarbonization and CO_2 sequestration initiative cluster is designed to develop, via a broad multinational collaborative effort, fuels decarbonization and carbon-sequestration technologies that would eventually make possible the use of fossil fuels under DOE's "Vision 21" goals (near-zero lifecycle CO_2 emissions, near-zero pollutant emissions) at low incremental cost compared to fossil-fuel technologies not involving CO_2 sequestration, as well as to advance, in developing and transition countries in the near term, syngas-based technologies that would facilitate the transition toward "Vision 21". Its high-priority elements are:

- collaborative efforts on CO_2 sequestration to develop standards for security of CO_2 storage, conduct environmental impact studies, carry out both region-by-region assessments of sequestration potential and detailed reservoir-by-reservoir analyses of storage capacity and other characteristics, and carry out demonstrations with monitoring of storage security;

- cooperation to promote energy-sector and environmental reforms in developing and transition countries making it more advantageous to produce multiple clean products simultaneously from syngas derived from natural gas, coal, and other carbonaceous feedstocks, coupled with collaborative R&D and demonstrations of technologies designed to reduce the cost of making hydrogen from carbonaceous feedstocks while facilitating the recovery of byproduct CO_2 for ultimate disposal.

To accomplish this the U.S. should:

- Advance in developing and transition countries strategies for making clean multiple products simultaneously from syngas derived from natural gas, coal, and other carbonaceous feedstocks, by promoting environmental reforms and energy-sector reforms that would make it feasible to sell the electricity coproduct to electric grids at prices that reflect its market value.

- Pursue collaborative R&D with other countries aimed at reducing the cost of recovering energy from methane clathrate hydrates without exacerbating the climate change problem.

- Pursue collaborative R&D with other countries aimed at substantially reducing the cost of making hydrogen from carbonaceous feedstocks while facilitating the recovery of the byproduct CO_2 for ultimate disposal and encourage demonstrations of new technologies.

- Through broad-based collaborative efforts on CO_2 sequestration: (*i*) develop international standards for CO_2 storage security, (*ii*) conduct environmental impact studies, (*iii*) carry out both broad-brush region-by-region assessments of the sequestration potential and detailed reservoir-by-reservoir assessments of storage capacity, security, costs, environmental impacts, via data collection and modeling, and (*iv*) carry out demonstrations, with monitoring of the security of CO_2 storage.

- Identify, develop, and demonstrate, via multinational efforts, promising integrated systems for hydrogen production and use, with sequestration of the separated CO_2.

Projects developed to meet near-term goals would be carried out largely by industrial joint ventures. USAID would be the lead agency for encouraging the needed environmental and energy-sector reforms. DOE would have the lead responsibility: (*i*) for providing cost/performance/environmental and other information for alternative syngas-based technologies and competing technologies, and (*ii*) for collaborative R&D targeted to support demonstration projects. Partial financing provided by the World Bank would also be helpful in launching these new technologies in the market, because Bank financing costs are typically less than those for commercial banks.

The U.S. interests would be:

- Overcoming institutional barriers to widespread deployment of gas liquids technology in multiple-product strategies would: (*i*) lessen world dependence on Persian Gulf oil and help limit oil price increases; (*ii*) forestall development of much more carbon-intensive synthetic liquid fuels from coal, with attendant climate change mitigation benefits; and (*iii*) provide greater market opportunities for those US firms that are at the forefront of gas liquids technology development.

- Overcoming the institutional barriers to multiple-product strategies based on coal gasification would enable the U.S. to take better advantage of its position as world leader in coal gasification technology. But stagnation in the domestic coal market requires that initial deployment activities be focused on developing countries. The pressing local and regional air pollution problems of coal-intensive energy economies imply large potential markets for US companies offering oxygen-blown gasification technologies, if ways could be found to make these technologies cost-competitive.

- The U.S. has much to gain by collaborating with other countries in the pursuit of CO_2 sequestration technologies and strategies. Norway is leading global activity in experience with aquifer disposal of CO_2, and Japan is aggressively investigating deep ocean disposal strategies. The U.S. could bring to such collaborations considerable expertise on enhanced resource recovery via CO_2 injection. Most commercial activity and expertise for EOR using CO_2 is in the U.S., so that activities emphasizing the dual objectives of EOR and CO_2 sequestration could provide significant opportunities for US industry. Likewise the technology for enhanced methane recovery from deep coal beds via CO_2 injection was pioneered in the U.S., so that if the technology can be established as a fully viable commercial activity, there would again be significant opportunities for US industry.

- The U.S. is seeking to engage developing countries in the pursuit of major climate change mitigation activities. Encouraging fossil fuel-rich developing countries via IERD^3 collaborations to evolve toward energy systems in which hydrogen plays major roles, with sequestration of the separated CO_2, would be an effective way to do this. The evolutionary strategy set forth in this initiative would advance these long-term goals while providing near-term benefits to developing countries in the forms of reduced air pollution and reduced dependence on oil imports.

Governmental Mechanisms and Institutions

U.S. government, in cooperation with the private sector, can more effectively develop, manage, and coordinate a portfolio of governmental activities in support of international ERD^3 cooperation consistent with an overarching vision of what this portfolio is to accomplish. To accomplish this, the following actions need to be considered:

- The President should establish a new interagency working group in the National Science and Technology Council (NSTC) to further develop and promote a strategic vision of the role of the government's contributions to international ERD^3 cooperation in support of this country's interests and values. This NSTC working group would:

  - have an interagency secretariat and an advisory board drawn from the private, academic, and NGO sectors;

  - be responsible for assessment of the government's full portfolio of activities in international ERD^3 cooperation – in consideration of the overarching strategy of the effort, the needed components of the innovation "pipeline" and links between these, and appropriate diversity and public-private- interface criteria – and for using the results of such portfolio assessment to help guide and coordinate the evolution of the relevant agency programs;

  - assist the agencies to strengthen their internal and external mechanisms for monitoring and reviewing projects, for terminating unsuccessful ones, and for handing off successful ones to the private sector at the appropriate time.

- In addition to these strengthened review procedures and the interagency portfolio assessment effort, needed improvements in the mechanisms for development and management of international ERD^3 cooperation programs within the agencies include

  - use of competitive solicitations by the agencies, in cooperation with foreign counterparts, to identify the most promising approaches to achieving portfolio and program goals, with a well developed business plan for moving a technology through the RD^3 pipeline a prerequisite for winning a competition;

- identification, by the cabinet secretaries or administrators of the key agencies selected by the NSTC working group to manage the ERD^3 cooperation portfolio, of appropriate accountable management chains with authority and budgets for implementing international ERD^3 programs;

- strengthening agencies' international capabilities through training, targeted hiring, and rotating national laboratory staff and outside academic and industrial technical experts through the agencies on a systematic basis, giving these persons senior professional status with significant responsibility for guiding program planning and policy.

- Furthermore, PCAST recommends the creation of a new Strategic Energy Cooperation Fund, supplementing existing funding and dispersed largely through a competitive process overseen by the new NSTC working group, in an amount starting at $200 million per year in FY2001 and increasing to $500 million per year by FY2005. Support for international ERD^3 programs from this fund would be

  - dispensed by the U.S. agencies with line responsibility for the programs, but allocated to them by a process of evaluation of competitive proposals prepared by the agencies – making the case for augmentation of their existing activities – under the direction of the NSTC working group and its advisory board;

  - multi-year in duration in most instances, to diminish the influence of annual funding cycles on project selection and continuation and to promote the continuity of commitment that has often been lacking in U.S. international-cooperation efforts.

VI. CONCLUSION

Pcast concluded that the United States and the world face an historic window of opportunity:

- Processes of energy-sector restructuring and regulatory reform that will be completed largely over the next decade will "lock in" the mechanisms that will determine success or failure in the dual aims of attracting the private capital needed to meet energy needs for economic development while addressing the huge public-goods and externality issues that the energy sector presents.

- Continuing processes of rapid urbanization in the developing countries mean that decisions made in those countries in the next few decades about the interaction of urban energy supply, transportation networks, information infrastructure, land-use planning, and building characteristics will likewise substantially "lock in", for the next century and even beyond, important aspects of the energy requirements and quality of life of the large majority of the world's inhabitants living in these urban agglomerations.

- The time requirements for moving new technologies through the innovation pipeline mean that much of the research intended to affect deployments in the 2020s, 2030s, and 2040s needs to be underway in the next decade. And the long service lifetimes of most energy-supply technologies and much the equipment and infrastructure governing energy end-use efficiency means that much of what is deployed in the 2020s, 2030s, and 2040s will still be in place toward the end of the next century.

- Thus the energy technologies and related infrastructures that are developed and deployed over the next few decades – supporting rapid energy growth in developing and transition economies and replacing existing capital stock in industrialized ones -- will strongly influence the trajectories of energy costs and end-use efficiencies, greenhouse-gas emissions, public-health impacts of air pollution, oil-import dependence, nuclear-energy-system safety and proliferation resistance...and much else of importance about the world energy system...for most of the next century.

- The globalization of innovation capacities, together with tightening constraints on domestic R&D spending, have sharply increased the attractiveness of cooperation to the United States for purposes of developing the energy technologies this country will require for domestic use. Simultaneously, the globalization of energy markets has increased the necessity of cooperation to gain access for United States energy companies to many of the largest markets for new technologies; and the globalization of environmental and security risks from inadequacies in the global portfolio of deployed energy options is sharply increasing the benefits to the United States of cooperation to improve that portfolio.

- Strengthening North-South cooperation on advanced energy technologies that can lower greenhouse-gas emissions while fueling sustainable economic development is by far the most promising available approach to securing developing-country participation in a larger collaborative framework for addressing the global energy-climate-development challenge.

The needs and opportunities for enhanced international cooperation on energy-technology innovation supportive of U.S. interests and values are thus both large and urgent. The costs and risks are modest in relation to the potential gains. Now is the time for the United States to take the sensible and affordable steps outlined here to address the international dimensions of the energy challenges to U.S. interests and values that the 21st century will present.

GLOBAL COMMUNITY RESPONSIBILITY – ROLE OF TECHNOLOGY AND PROJECT DEVELOPERS, FINANCIERS, CONSUMERS, AND GOVERNMENTS

Barry K. Worthington
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I was asked today to speak in place of David Jhirad, who is with the Department of Energy's Policy Office. David unfortunately was compelled to be in Paris today and he asked me to express his regret at not being able to be present.

I suppose that I was asked to deliver this address titled "Global Community Responsibility – The Role of Technology and Project Developers, Financiers, Consumers, and Governments" because I was honored to be selected to moderate a panel of the same name a bit later this afternoon. In the afternoon panel we have experts representing these various perspectives who will explain how their particular community perceives an obligation to "global responsibility."

I then in this address will strive to provide a more global perspective.

I harken back to the 17th Congress of the World Energy Council, held last September in Houston. We organized that event under the theme "Energy & Technology – Sustaining World Development into the Next Millennium."

This theme was carefully crafted – as required to gain concurrence from 100 countries. Please note that the phrase – Sustaining World Development - - not "Sustainable Development." This was not intended as a slight to the concept of sustainable development, but rather to express a collective view that the nexus of energy & technology will be the force that moves our society after the year 2000.

Our global challenge – our global community responsibility, is to insure that we try our best to put energy resources and the advanced technology needed to utilize those resources, in the hands of the 2 billion people in the world who lack access to these basic building blocks of modern society.

We who attend this conference each year marvel at the tremendous success that has been derived from our U.S. research and development effort. The examples from the U.S. Department of Energy Clean Coal Technology Program – the outstanding research agenda of the Electric Power Research Institute, the Gas Research Institute and our federal labs have produced a magnificent array of technological improvements that provide our consumers with abundant, economical and environmentally sound energy choices.

How can we deploy these technologies in other countries and particularly developing countries and particularly to citizens of those countries who lack the basic tools to harness energy? What responsibility do we have to provide a single light bulb for an Asian home so that a ten year old can read a book after dark?

What responsibility do we have to a housewife in Africa who spends hours each day gathering firewood to be able to cook a simple meal?

And what responsibility do we have to a hospital in South America to provide electricity to enable proper handling of medicines, of ultraviolet light to kill bacteria and viruses and to provide for a host of sanitary conditions that we take for granted.

The answer is that all of these become our global community responsibility. It is a task that we are compelled to accomplish, to strive to spread the economic, environmental, social and developmental gains available from access to energy resources and energy technology to the forty percent of the world's population lacking this today.

Is this some theologically driven do-gooder agenda more appropriate for Sunday morning church services? No! Rather, it is the voice of the international business community and global energy industry.

The following points were expressed by the 4,000 delegates to the 17th Congress of the World Energy Council, representing 100 countries, all industry and government executives in the energy business.

"The world is set for continuing and necessary economic growth, and holds an abundance of accessible energy resources that are more than sufficient to meet this growth."....

"The liberalization of energy markets, coupled with the right institutional and regulatory framework, is attracting substantial private investment to meet energy needs but the allocation of these funds now and the adequacy of their future flow to the energy sector give grounds for concern."....

"The problem of world energy poverty persists. Today, as was the case at the last Congress three years ago, one-third of the world's population do not have access to commercial forms of energy, while 20 percent of the world's population consumes 80 percent of the world's energy production. Too little progress has been made in addressing those needs. The problems in rural areas are particularly acute and new partnership and economic models are needed to address the problem."...

"A third of the world's 5.9 billion people do not currently have access to commercial energy. Most of these people live in developing countries where 90 percent of today's burgeoning population growth is occurring. By 2020 there will be roughly another 2 billion people in the world, mostly in developing countries. The WEC believes that global energy consumption will grow by about 50 percent in the next 20 years. Even if the world were organized to use its natural and human resources optimally, this would pose a significant challenge."...

"Investors should work with government and international financial institutions to extend the ability of commercial energy to populations in developing nations as rapidly as possible."....

Mechanisms that can foster technology transfer to developing countries include:

- Restructuring and commercialization of energy enterprises;

- Energy partnerships such as the information sharing partnerships sponsored by USEA and funded by the U.S. Agency for International Development and the U.S. Department of Energy;

- Transparent regulatory, pricing and procurement policies that facilitate foreign investments and technology exports;

- Investments in science and technology development given a longer term and more global view;

- Focused foreign assistance aimed at providing tools for developing countries to find ways to solve their own problems and a recognition that energy development and utilization deploying advanced technology can itself be a tool to solve other systemic problems in education, health care, sanitation, infrastructure development and development of the human spirit.

The central question for attendees at this conference is to ask the question, "Why coal and why clean coal technologies?"

The answer to why coal has a number of dimensions. "Is there a role for coal" along side the well-recognized "dash for gas." The simple answer that all of you know is yes – yes unless coal can not be competitive economically under the terms and conditions that a society imposes. And these will vary greatly by region and even over time in the same country.

Recent global economic crisis in Asia and threats to stability in South America have reminder some countries of the value of indigenous resources. Domestic coal reserves look better when dramatic currency devaluation make imported fuels double or triple in hard currency cost.

Still, the central issue is how can we expect a developing country; or, in this context, a country with a transitional economy, to pay the premium for advanced technology.

If a country has rapidly growing power requirements and rapidly growing societal pressures for other basic human needs – who can expect them to select any generation option other than the lowest capital cost which may even represent the lowest operation and maintenance cost? The issue seems to be one of wishing to sell a Cadillac to a customer who may have trouble making the down payments on a Saturn.

Other non-financial barriers can include hesitancy on the part of government officials including newly formed regulatory commissions. Often these officials are learning the rudimentary aspects of their new jobs – dealing with approval processes for advance technology projects will be daunting.

Also, developing countries and transitional economics have learned some bad habits from us, their western counterparts. Unfortunately, these bad habits include the "NIMBY" syndrome – "Not-in-my-backyard," as well as "BANANA – build absolutely nothing anywhere nor anytime." Exporting environment justice and other such concepts is occurring at a rapid pace, and will complicate technology transfer.

Another social trend that we have exported is unrealistic expectation of the role of renewables. This is aggravated by some of us – energy business leaders who occasionally offer provocative thoughts that paint the future of non-fossil energy in a light that may be politically fashionable and generates lots of media attention – but will be unsustainable at the end of the day.

Can someone make headlines by claiming that the energy future looks black – black as in coal? Probably not!

Let's look at some pronouncements from the past that made headlines at the time.

"Although we hear much about various future sources of energy, the work of our civilization is wedded to the fossil fuels – coal, oil and natural gas – sources of energy that are dwindling rapidly."...1974

"Despite its much touted abundance, coal will not become our major near-term solution to the energy problem. The only realistic two options for the short term are wood and wood waste, and on-site solar technologies, such as solar heating, small hydropower and small wind."...1979

"We must rapidly adjust our economics to a condition of chronic stringency in traditional energy supplies."... 1979

"It is now abundantly clear that the world has entered a period of chronic energy shortages that will continue until mankind has learned to harness energy from renewable sources."...1980

While we did not make the front page of the New York Times, let me read one statement from the conclusions of the 17th Congress of the World Energy Council.....

"....current fossil fuel resources are sufficient to sustain global economic growth well into the next century and will be used in increasing amounts..."

"...coal will remain the principal energy supply resources for many developing countries..."

Financial barriers to CCT deployment are clear and well understood. Developers philosophy, driven by their natural inclination to build only profitable projects is clear. Governments and consumers willingness or unwillingness to embrace unfamiliar technology can also be understood.

What then are the incentives, the motivators, and the peripheral factors in a market driven society that can lead a country to embrace clean coal technology? We hope to explore in more depth what these issues are and perhaps explore prescriptions to the question... "What is all of our global community responsibility?"

What is our responsibility to provide access to energy and technology to the 2 billion citizens of the world that lack both – so that they can, "Sustain Development into the Next Millennium." This is the dialog for the panel discussion later today. Thank you.

LUNCHEON

Issue 3: Coal in Tomorrow's Energy Fleet: Pressures and Possibilities

COAL IN TOMORROW'S ENERGY FLEET: PRESSURES AND POSSIBILITIES

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ABSTRACT

The Clean Coal Technology (CCT) Demonstration Program has a long history of success in improving energy efficiency and reducing the environmental impact of coal-fired power generation. Through the program, government-industry partnerships produced technological solutions to the environmental problems of the times. From the early rounds of the CCT Demonstration Program (with their emphasis on acid rain), through later rounds (with their emphasis on improved efficiencies), the CCT Demonstration Program answered the environmental challenges to coal of the 1980's and early 1990's.

As we move into the 21st century, coal use faces new and continuing challenges. Deregulation is changing the way the industry operates and invests in new facilities and technology. Environmental concerns will lead to tighter regulations, especially for $PM_{2.5}$, NO_X, *and possibly including greenhouse gas emissions. A new Department of Energy program, Vision 21, will build on the successes of the CCT Demonstration Program and answer the challenges facing coal in the 21st century, helping coal remain an important part of the world's energy mix.*

This talk will explain the Vision 21 program: what it is, what will make it work, and how Vision 21 plants differ from conventional coal plants. The talk will outline the goals and approaches of Vision 21, and the R&D needed to make it a success.

FULL PAPER UNAVAILABLE AT TIME OF PRINTING

PANEL SESSION 1

Issue 1: Deploying CCTs

OVERVIEW OF THE ECONOMICS OF CLEAN COAL TECHNOLOGIES AS COMPARED WITH ALTERNATIVES FOR POWER GENERATION

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ABSTRACT

For new coal-based power plants to be competitive they must have low capital cost, high efficiency, and excellent environmental performance. Continued deregulation of the electric utility market in the U.S. and overseas has resulted in "bottom line" economics becoming the key criteria for selection of new power generation technologies. Since the early 1990's there have been significant reductions in the capital cost of most power generating technologies in response to the global market demand for competitive power generation. Natural gas-fired combustion turbines and combined cycle plants have dominated the recent power generation markets in the U.S. and in much of Europe, with total plant costs for combined cycle plants dropping to as low as $400/kW in early 1998.

Improvements in the cost and efficiency of combustion turbines has also lead to significant reductions in the capital cost and higher efficiencies for advanced coal-based power generation technologies, such as integrated gasification combined cycle (IGCC) and pressurized fluidized bed combustion (PFBC). Improved combustion turbine efficiencies mean that the front-end gasification facilities can be smaller and therefore less expensive on a per kilowatt basis.

This paper reviews EPRI's capital cost estimates and performance projections for clean coal-based power generation technologies and compares them on a consistent basis with conventional alternatives for electric power generation. For this paper, clean coal technologies include IGCC, PFBC, and hybrid gasification/PFBC systems. Conventional power generation technologies include pulverized coal-fired power plants and natural gas-fired combined cycle power plants.

I. INTRODUCTION

The deregulation of the electric power industry, accompanied by the uncertain impact of carbon dioxide (CO_2) on global warming, has put a premium on maximizing the overall efficiency of electric power generation facilities. Coal, in particular, is seen as a major contributor to global warming due to its high carbon/hydrogen ratio. The Clean Coal Technology Program was initiated to develop and commercialize advanced technologies as an alternative to conventional pulverized coal-fired (PC) power plants for generating electricity from coal. The overall objectives of the advanced technologies are to improve overall efficiency and reduce emissions, while maintaining competitive capital costs.

Clean Coal Technologies (CCT) such as Integrated Gasification Combined Cycle (IGCC) and Pressurized Fluidized Bed Combustion (PFBC) have been developed to commercial size over the past two decades and have demonstrated that they are able to achieve high plant efficiencies, while meeting extremely stringent air emission standards. The main issue preventing the widespread adoption of IGCC and PFBC technologies has been their relatively high capital cost.

Since the early 1990's there have been significant reductions in the capital cost of most power generating technologies, including PC plants, in response to the global market demand for competitive power generation. Natural gas-fired combustion turbines and combined cycle plants have dominated the recent power generation markets in the U.S. and in much of Europe, with total plant costs for combined cycle plants dropping to as low as $400/kW in early 1998.

Improvements in the cost and efficiency of combustion turbines has also lead to significant reductions in the capital cost and higher efficiencies for advanced coal-based power generation technologies, such as IGCC and PFBC. Improved combustion turbine efficiencies mean that the front-end gasification facilities can be smaller and therefore less expensive on a per kilowatt basis.

This paper reviews EPRI's capital cost estimates and performance projections for clean coal-based power generation technologies and compares them on a consistent basis with conventional alternatives for electric power generation. For this paper, clean coal technologies include IGCC, PFBC, and hybrid gasification/PFBC systems. Conventional power generation technologies include pulverized coal-fired power plants and natural gas-fired combined cycle power plants.

II. DESIGN APPROACH

Previous EPRI studies of advanced coal technologies were conducted by different teams of contractors that often presented the cost breakdown in different formats and used differing assumptions with regard to date, location, coal type and ambient conditions. The methodology described in EPRI's Technical Assessment Guide was used to normalize the plant performance and cost estimates for this paper. The plant designs are based on a grassroots facility at a mid-western location (nominally Kenosha, WI). The site is assumed to be clear and level with no special problems. Other general study criteria are as follows:

- Performance is evaluated at 59°F and a condenser pressure of 2.0 inches HgA.
- The design coal is Illinois #6 with 3.3% sulfur and 10,982 Btu/lb (HHV) as rec.
- Sulfur capture is 95 percent, except for IGCC, which is 99 percent.
- Units are considered base loaded.
- Equipment sizing and sparing is based an availability of 85 percent.
- Equipment is designed for a 30-year plant life.
- Coal is delivered to the site by rail.
- Limestone (94.1% $CaCO_3$) is delivered to the site by rail.
- Onsite emergency ash storage is sized for 90 days. Final disposal is off site.

III. TECHNOLOGY DESCRIPTIONS

Pulverized Coal (PC)

The major components of the nominal 400 MW pulverized coal-fired units described in this paper include coal-handling equipment, steam generator island, turbine-generator island, FGD system, fabric filter, bottom and fly ash handling system, and wet stack with no flue gas reheat. The cost and performance data include low NOx burners and post combustion control of NOx by selective catalytic reduction (SCR).

The steam generator island includes the coal pulverizers, burners, waterwall-lined furnace, superheater, reheater, and economizer heat transfer surface, soot blowers, Ljungstrom air heater, and axial-flow-forced and induced-draft fans. For subcritical units the steam conditions are 2400 psig/1000°F superheated steam, with a single reheat to 1000°F. For the supercritical units the conditions are 3500 psig/1050°F superheated steam, with a single reheat to 1050°F.

The turbine-generator island includes the main, reheat, and extraction steam piping, feedwater heaters, condenser, mechanical draft cooling towers, boiler feed pumps, and auxiliary steam generator. The steam turbine is a tandem-compound unit, designed for constant pressure operation with partial arc admission. The feedwater heating system uses two parallel trains of seven heaters, including the deaerator; the boiler feed pumps are turbine driven. The condenser is designed to operate at 2.0 in. Hg back pressure.

The FGD system is a wet-limestone, forced-oxidation spray tower system, with one 100% module and no spare. The design limestone addition rate is 1.05 moles $CaCO_3$/mole SO_2 removed, and the SO_2 removal is 95%. The forced oxidation system is designed to produce wallboard-grade gypsum. However, the O&M costs in this paper reflect gypsum disposal by stacking due to uncertain market conditions for the gypsum products. The gypsum product is dewatered to 90% solids by centrifuges. The flue gas enters the stack at about 125°F, and the stack is designed for saturated flue gas conditions. The particulate collection system is a reverse-gas fabric filter (baghouse), located ahead of the FGD system. Two 50% baghouse modules are connected in parallel.

Pressurized Fluidized-Bed Combustion (PFBC)

The pressurized fluidized-bed combustion units described in this paper are based on the bubbling-bed technology developed by ABB Carbon. Compressed air is supplied to the boiler, and the coal is burned under pressure. Dust is removed from the flue gas, which then passes through a gas turbine that drives a generator and an air compressor. High pressure steam is raised in tubes positioned in the boiler, and the steam turbine generates approximately 80% of the net power output. Limestone is fed to the boiler to capture sulfur released from the coal. Major systems include coal-handling equipment, boiler island, turbine-generator island, particulate removal, ash handling, and other balance of plant facilities. The boiler island also includes the gas turbine and economizer.

A pressure vessel operating at 170-220 psi contains the boiler, multiple cyclone trains, cyclone and bed ash cooler circuits, and bed ash reinjection storage vessels. These latter vessels store bed material at operating temperature, as load changes involve the rapid lowering and raising of bed level. This exposes or covers in-bed heat transfer surface, which regulates both steam production and the gas turbine inlet temperature. The combustion air enters the boiler through a sparger-type distributor at the base of the boiler. The coal is fed either as a paste through a series of nozzles, each supplied by its own pump. The dry sulfur sorbent is either blended with the coal or is fed pneumatically at the same elevation using a lesser number of nozzles. The cyclones are used to remove the majority of the dust from the flue gas prior to it entering a specially designed ruggedized gas turbine. The gas turbine inlet conditions are nominally 220 psia and 1550°F. The remaining dust is removed by baghouse before the flue gas is discharged to atmosphere.

For subcritical units the steam conditions are 2400 psig/1000°F superheated steam, with a single reheat to 1000°F. For the supercritical units the conditions are 3500 psig/1050°F superheated steam, with a single reheat to 1050°F. Nominal net plant output in both cases is 350 MW.

Integrated Gasification Combined Cycle (IGCC)

The gasification-combined-cycle plant described in this paper is based on the Dynegy gasification process. The Dynegy coal gasification process is an oxygen-blown, coal/water slurry fed, entrained, two-stage upflow slagging gasifier. In the first stage, coal/water slurry is introduced with oxygen via two horizontally opposed burners. Molten slag is removed from the bottom of the first stage into a water bath and continuously removed by pressure letdown. A second injection of coal/water slurry is introduced at the upper outlet of the first stage, which reduces the second stage outlet temperature to about 1900°F.

The basic Dynegy flow scheme used in this paper consists of the following sequential processing units:

- Coal receiving and handling
- Coal grinding, slurrying, and pumping
- Lower Pressure (68 psia) ASU supplying 95% purity oxygen to the gasifiers
- Gasification of preheated coal/water slurry with oxygen in a two-stage refractory lined vessel (slurry only to second stage)
- Slag removal by continuous letdown
- Raw gas cooling with saturated HP steam raising in a downflow fire tube heat exchanger
- Particulate removal in a ceramic candle filter at about 650°F with recycle of char back to gasifier first stage
- Water scrub to remove chlorides
- Low temperature gas cooling and COS hydrolysis
- Acid gas removal using an MDEA-based process for selective removal of H_2S.
- Conversion of H_2S to sulfur in Claus sulfur recovery units equipped with Tail Gas Treatment Unit (TGTU)

- Clean fuel gas saturation and preheating to 520°F for introduction together with superheated intermediate pressure steam into the gas turbine combustors
- HP saturated steam from the raw gas cooling is sent to the gas turbine HRSG for superheating and the combined steam sent to the steam turbine.

The combined cycle system consists of two GE 7FA gas turbines, each equipped with a heat recovery steam generator (HRSG), and a single reheat steam turbine generator. The HRSG provides superheating of high pressure (HP) steam and reheating of intermediate pressure (IP) steam. It also generates HP, IP, and low pressure (LP) steam and preheats boiler feedwater. HP saturated steam generated in gasification syngas coolers is combined with steam from the HRSG HP Evaporator for superheating in the prior to admission to the steam turbine. The steam conditions are 1450 psig/1000°F superheated steam, with a single reheat to 1000°F. The net IGCC output is approximately 590 MW.

Advanced PFBC and GCC Systems

For conventional PFBC plants, the gas turbine inlet temperature is fixed by the combustor operating temperature of 1550°F-1650°F, which limits overall cycle efficiency to less than 42%. By raising the inlet temperature, cycle efficiency can be substantially improved. A topping combustor can be added between the PFBC and the gas turbine. In these advanced systems the gas turbine is more fully utilized since the temperature of the gases entering is dictated by the limits of the turbine rather than the PFBC. Downstream, the economizer may become a heat recovery steam generator since the temperature of the turbine exhaust is significantly higher (typically around 1050°F). Low Btu syngas from a partial gasifier (or carbonizer) provides the fuel for the topping compustor, while char from the gasifier is used to fuel the PFBC.

Two such advanced systems are included in this paper. They differ in the degree of carbon conversion in the partial gasifier. One is essentially a topped PFBC plant, while the other is primarily an air-blown gasification plant with a smaller PFBC plant for combustion of the char. The gasification plant incorporates M. W. Kellogg Company's (MWK) transport reactor design as both the gasifier and the combustor. The topped PFBC plant is based on a Foster Wheeler (FW) design that incorporates a bubbling-bed carbonizer and a circulating PFBC.

Both plants incorporate an advanced gas turbine in order to minimize the cost per unit of output, while maximizing the overall efficiency. The technology selected for this study is a Westinghouse Advanced Turbine System (ATS), currently under development. The rotor inlet temperature (RIT) of these machines is planned to be 2750°F compared to an RIT of 2350°F for the F-technology machines in current use. The ATS is expected to generate around 300 MWe and operate with a pressure ratio of 28:1. To maintain the pressure differential between the compressor discharge and the turbine inlet at an acceptable value, a booster compressor was required in the compressor discharge line.

The ATS is fired with coal-derived fuel gas burned using air from the compressor supplemented with vitiated air from a char combustor. These air supplies are delivered at elevated temperatures, which prevents the use of normal combustion canisters provided with the turbine.

The burner selected for this application is a multi-annular swirl burner (MASB), with multiple MASBs located in silos external to the ATS. The fuel gas contains ammonia compounds that when burned could produce large amounts of NOx. The MASB limits such emissions by means of rich-quench-lean combustion. High temperature, high pressure (HTHP) ceramic filters are used to remove the residual char from the fuel gas prior to combustion in the MASB.

As the Kellogg GCC design is air blown, only around 83% of the carbon is converted to syngas in the carbonizer, with the remaining char being burned in a pressurized combustor. Because of the lower amount of high-grade heat produced, the Kellogg GCC design only supports a lower pressure steam cycle. In the Foster Wheeler design, only around 56% of the carbon is converted to fuel gas in the carbonizer. Consequently, to provide the amount of fuel gas required to meet the required RIT, the coal feed rate is higher than for the Kellogg unit. The residual char is burned in a circulating PFBC along with a small amount of fresh coal (approximately 7% of total coal feed) and there is sufficient high-grade heat available to support a higher pressure, more efficient steam cycle. Moreover, as more steam is raised, the steam turbine output is also substantially higher than that of the Kellogg GCC. Consequently, in satisfying the demands of the ATS, the overall net power output of the Foster Wheeler unit is nearly 690 MW, or approximately 50% greater than the net advanced GCC output of 460 MW.

Key design and operating parameters for the advanced GCC and PFBC plants are summarized as follows:

	Advanced GCC	Advanced PFBC
Steam conditions, psig/°F/°F	1800/1000/1000	2400/1000/1000
HTHP filter temperatures, °F		
Gasifier/Carbonizer	750	1400
Combustor	750	1600
Feed top size, microns	500	3200
Ca/S molar ratio (for 95% retention)	1.49	1.73
% carbon conversion in carbonizer	83	56
% of total coal to carbonizer	100	93

Figure 1 shows a schematic process flow diagram for the advanced GCC plant based on M. W. Kellogg's transport gasifier. Coal and sorbent are both dried and crushed to a top size of 500 microns and fed to the single-train gasifier, operating at 450 psia and 1670°F, through lock hoppers and pneumatic conveying systems. The gasifier consists of two sections: a lower, relatively short, large-diameter section where the coal and sorbent feed are mixed with recycled char; and an upper, taller, small-diameter section where most of the gasification occurs. The gaseous reactants, air and steam, are introduced at the bottom of the mixing zone. Most of the sulfur released from the coal is captured by the sorbent as calcium sulfide.

All the feed stock is carried from the mixing zone into the riser and out of the reactor. The majority of the unreacted char and sorbent-derived material leaving the riser is captured by a cyclone assembly and recycled back to the mixing zone. The fuel gas and residual char leaving the cyclone are cooled to 750°F in a fire-tube exchanger raising high-pressure steam. HTHP filters, with metal filter elements, are used to remove the residual char from the fuel gas, which then passes on to the MASB.

The char collected by the HTHP filter and excess char from the recycle loop are cooled in screw coolers, the heat being transferring to the boiler feed water. The cooled char is then pneumatically conveyed into the pressurized combustor operating at 450 psia and 1650°F. This too is a transport reactor with a mixing zone and riser section, followed by a cyclone and HTHP filter. Unlike the gasifier, a heat exchanger is incorporated into the recycle loop to remove the heat released and raise steam. The combustion air entry is staged to control NOx emissions.

The dust-free flue gas is used as the oxidant to burn the dust-free fuel gas in the externally mounted MASBs. The expanded gases exhaust into the heat recovery steam generator (HRSG) before being sent to the stack. The heat transferred raises additional steam, and provides all the superheat, reheat, and economizer duty. The steam conditions are relatively modest at 1800 psig/1000°F/1000°F.

Figure 2 shows a schematic process diagram for the advanced PFBC plant based on the Foster Wheeler process. Coal and sorbent are both dried and crushed to a top size of 1/8-inch and fed to the single-train carbonizer, operating at 480 psia and 1780°F, through lock hoppers and pneumatic conveying systems. The carbonizer is a jetted, bubbling fluidized-bed design. The coal, sorbent, air, and steam are fed at the bottom, creating the jet and promoting rapid mixing of the feed stock with the bed material. The vessel consists of two sections: a lower, tall, small-diameter section containing the bubbling bed, where most of the carbonization occurs; and an upper, shorter, larger-diameter section, where the gas velocity is reduced and most elutriated solids disengage and settle back to the bed.

The unreacted char is transferred from the carbonizer to the circulating PFBC. A portion of the char leaves the carbonizer with the fuel gas, the majority of which is captured by a cyclone assembly. The fuel gas and residual char leaving the cyclone are cooled to 1400°F by injecting water into the flow stream. High temperature, high pressure (HTHP) ceramic filters are used to remove the residual char from the fuel gas, which then passes on to the MASB.

A small amount of coal (approximately 7% of the total coal feed) is also fed to the combustor to utilize excessive oxygen, maximizing heat release and steam turbine power output. The combustor operates at 430 psia and 1580°F, and contains all of the heat transfer surface. Air entry is staged to control NOx emissions. It is expected that almost all the sulfide contained within the char will be oxidized to the sulfate. The flue gas leaving the combustor is not cooled so the HTHP ceramic filters operate at 1580°F.

The dust-free flue gas is used as the oxidant to burn the dust-free fuel gas in the externally mounted MASBs. The expanded gases exhaust into the heat recovery unit (HRU) before being sent to the stack. The heat transferred provides the primary superheat and economizer duty.

Natural Gas-Fired Combined Cycle

The natural gas-fired combined cycle system consists of two GE 7FA gas turbines, each equipped with a heat recovery steam generator (HRSG), and a single reheat steam turbine generator. The steam conditions are 1450 psig/1000°F superheated steam, with a single reheat to 1000°F. The nominal plant output is slightly over 500 MW at ISO conditions, with a combined cycle efficiency of around 55% (LHV basis).

Utilizing the more advanced "G" and "H" technology combustion turbines firing at 2,600°F, the combined cycle efficiency can approach 58 to 60% (LHV basis), with single-train net plant outputs approaching 400 MW.

IV. OVERALL PLANT PERFORMANCE AND COST ESTIMATES

Figure 3 compares the relative net plant heat rates for all of the technologies considered in this paper. All heat rates are expressed on a higher heating value basis. PFBC and IGCC units are expected to have net heat rates that are 10 to 13% lower that that for the subcritical PC. Advanced PFBC and GCC plants offer the potential for heat rates that are around 25% better than those for the subcritical PC plant, approaching the heat rates offered by today's natural gas-fired combined cycle plants.

The relative Total Plant Costs (TPC) shown in Figure 4 include direct field costs (materials, labor and subcontract), indirect field costs, engineering, and contingency. Direct field material costs are for the permanent physical plant facilities and include major equipment, material, and freight to the plant site. The direct labor man-hours, wage rates, and productivity used as the basis for this study were estimated based on experience for the construction of conventional process and power plants in the mid-west region. Payroll additives and craft benefits are included.

Subcontract costs include equipment and materials furnished by major subcontractors, including the installation labor costs and the indirect costs of the subcontractors. For example, the air separation unit in the IGCC plant is estimated as a turnkey subcontract and includes all of the necessary support facilities, utilities and engineering.

Indirect field costs are costs that cannot be directly identified with any specific construction operation for the permanent plant facilities, but nonetheless support the general construction operation.

Home office engineering costs include labor for the engineering design, procurement, technical services, administrative support, and project management services; office expenses such as materials, communications, reproduction, computer, travel, etc.; and office overhead costs and fee

Project contingencies ranging from 10 to 15% have been added to the coal-based technologies, depending on the level of development of the technology. Project contingencies for the natural gas-fired technologies were assumed to be only 5% due to the turnkey nature of these plants.

The costs were developed assuming a mature technology. In other words, the plant is expected to achieve the rated performance as designed and built, with no process or equipment modifications required. Therefore, no process or scope contingency was included.

As shown in Figure 4, IGCC plants are expected to have capital costs that are slightly higher than the capital costs for PC plants, while the capital costs for PFBC plants is expected to be slightly lower than for PC plants. The advanced coal plants, when they become commercially available, are expected to have capital costs that are 20 to 25% lower than today's PC plants.

V. ECONOMIC EVALUATION

The Energy Information Administration (EIA) Annual Energy Outlook for 1999 projects that the real long-term price of natural gas will rise while that of coal will fall. The price trend for these two fuels is presented in Figure 5. Between 2000 and 2020 the price of gas is expected to escalate by approximately 1.0% per year while that of coal decreases by nearly 1.3% per year.

The fuel cost data presented in Figure 5 have been used to calculate constant dollar levelized costs of electricity using the procedures and financial parameters outlined in EPRI's Technical Assessment Guide. The analysis assumes a book life of 20 years, a capacity factor of 85%, and a hypothetical plant startup date of 2000 (even though the advanced technologies are not expected to be commercially available for another 5 to 10 years).

The resulting relative levelized costs of electricity shown in Figure 6 indicate that IGCC and PFBC appear to be competitive with today's pulverized coal plants. However, none of the currently available coal technologies can compete with a natural gas-fired combined cycle, even with today's increasing prices for combustion turbines.

It should be noted that the relative levelized cost of electricity comparisons shown in Figure 6 are based on mean fuel prices for the USA and that fuel prices vary regionally. For example, in the states surrounding the Powder River Basin, coal is more competitive while in the northeastern states it is less competitive.

In the longer term, advanced GCC and PFBC technologies are expected to become competitive with natural gas-fired combined cycle plants, especially with the average price differential for gas and coal increasing at approximately 2.3% per year. Figure 7 shows the relative levelized cost of electricity for all of the technologies based on a year 2010 startup. By that time, the first year price for natural gas is expected to be \$3.08/MMBtu while the price for coal will be \$1.06/MMBtu. The resulting price differential of slightly over \$2.00/MMBtu is about 40% greater than the price differential in year 2000. As shown in Figure 7, the relative levelized costs of electricity for both of the advanced coal technologies are slightly less than that for the advanced natural gas-fired combined cycle.

Figure 8 shows the change in relative levelized costs of electricity for the advanced coal and gas technologies as a function of plant startup year. By 2010, the relative ranking of the coal and gas technologies have reversed, with the advanced coal technologies being more favorable.

The implications of this economic comparison are clear: future electricity prices will rise higher if the advanced, coal-fired option is not available. As it has in the past, fuel diversity will lead to lower electricity costs but only if the technology is developed to take advantage of the lower raw energy price of coal.

VI. REFERENCES

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3.) Annual Energy Outlook 1999, Energy Information Administration, Washington, D.C., December 1998.
4.) EPRI TAG™ Technical Assessment Guide – Electricity Supply.

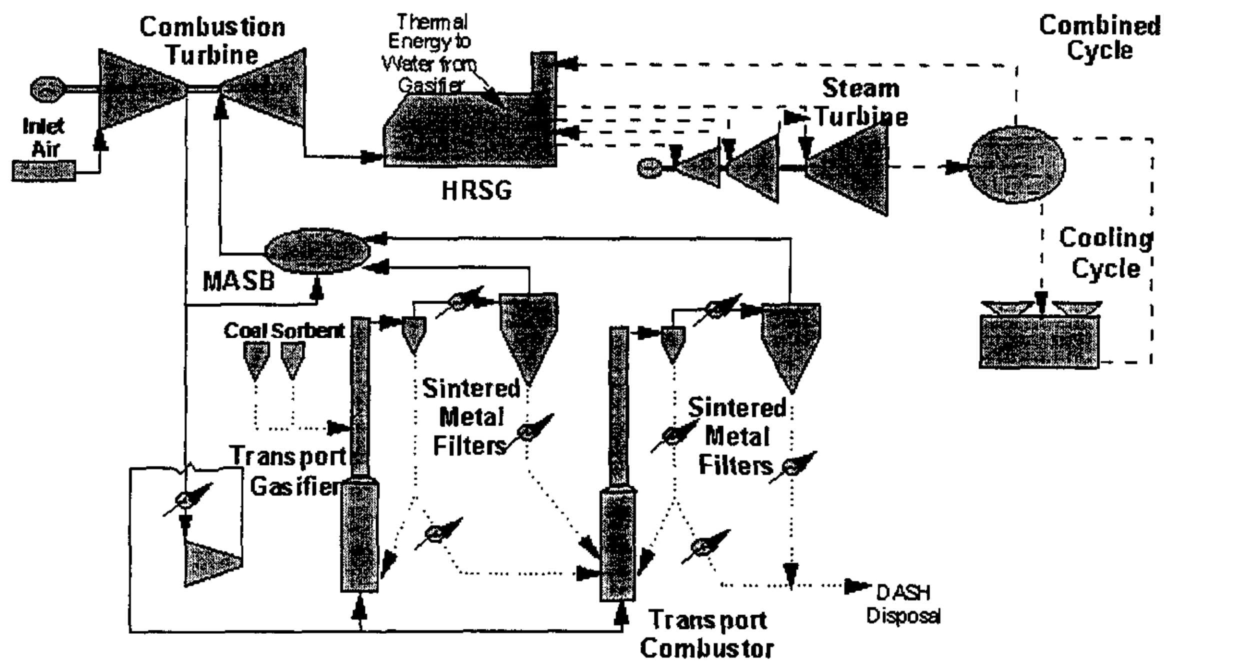

Figure 1. Kellogg Air-Blown IGCC

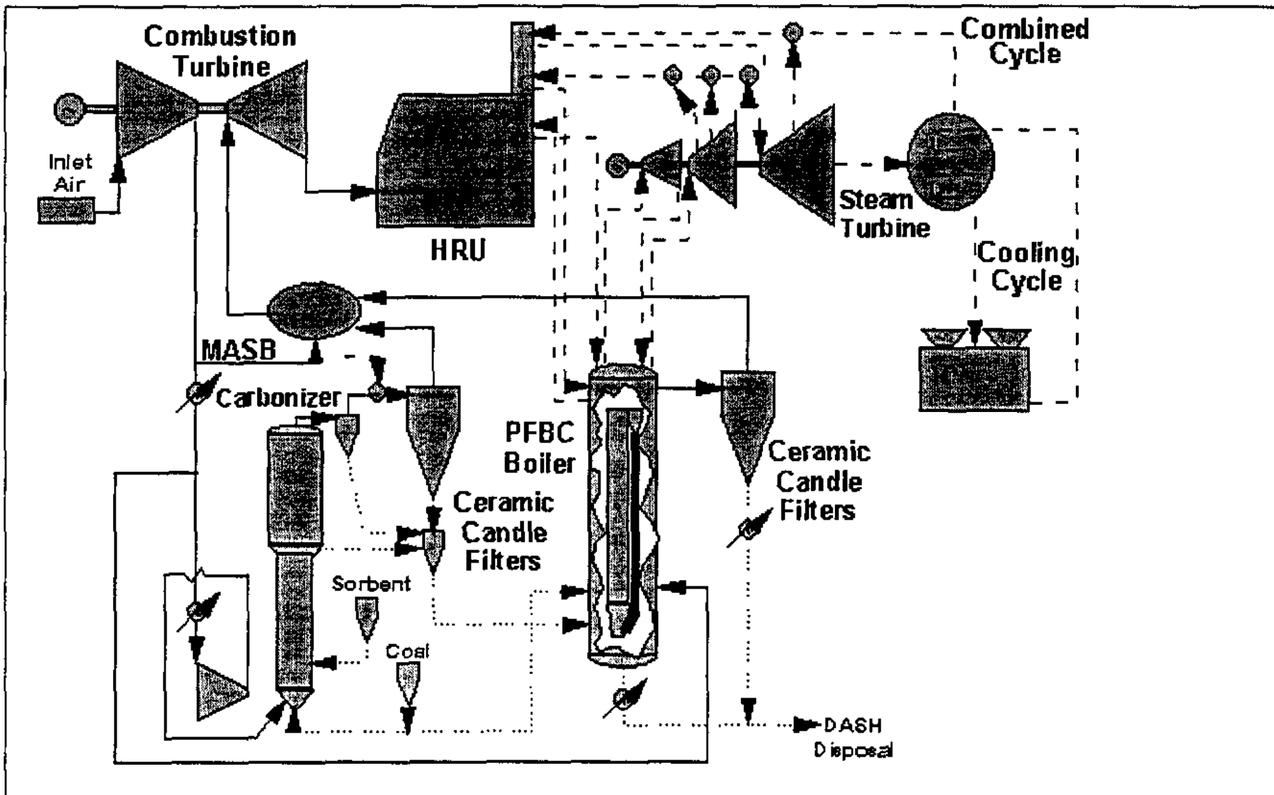

Figure 2. Foster Wheeler Topped PFBC

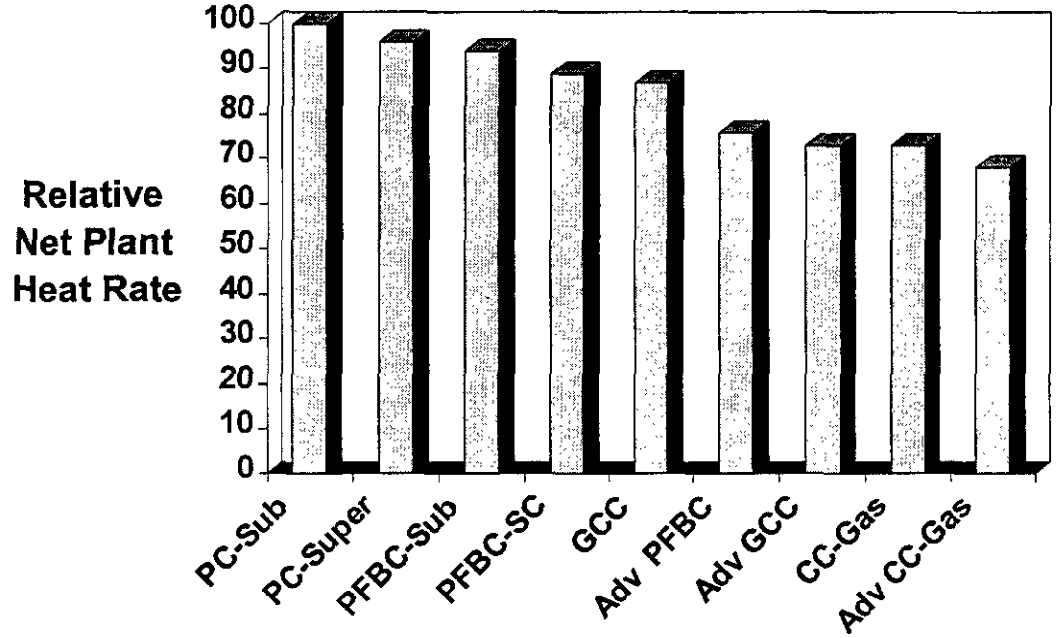

Figure 3. Net Plant Heat Rate Comparison

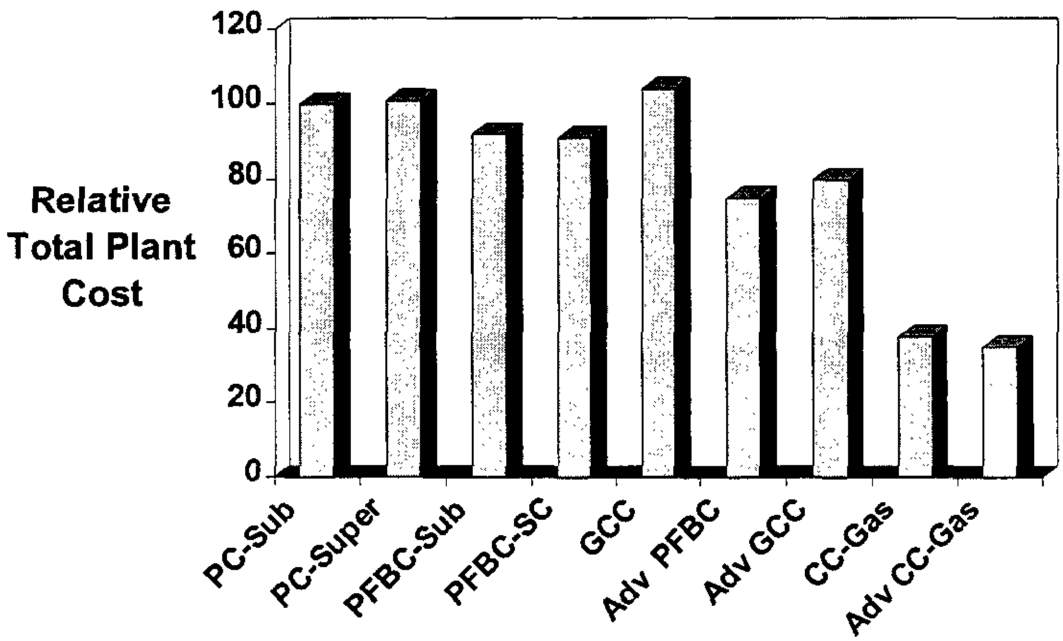

Figure 4. Total Plant Cost Comparison

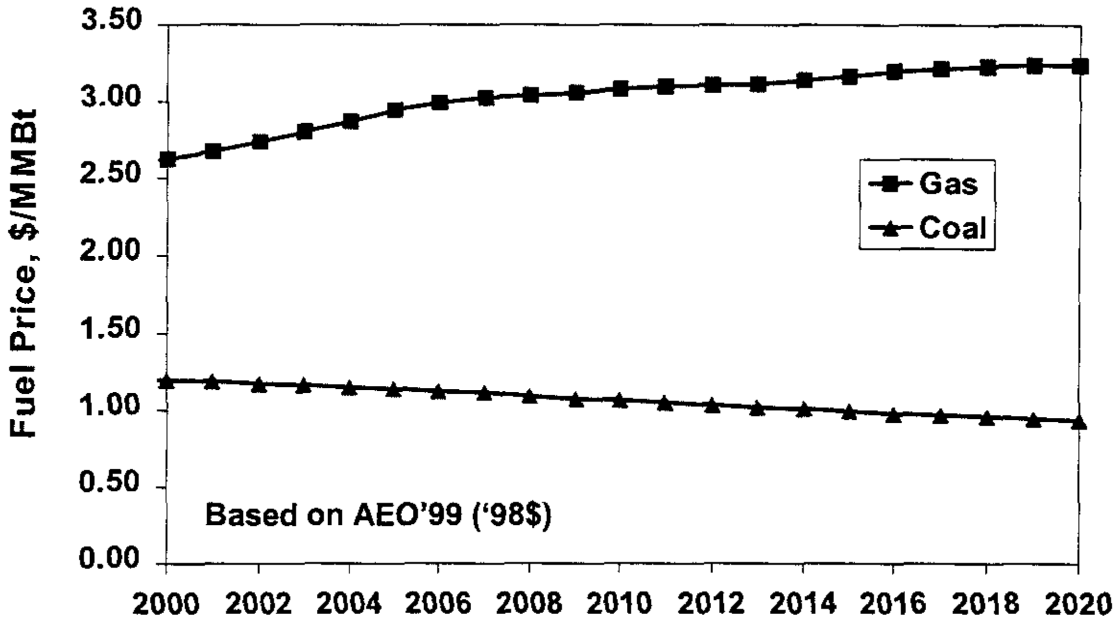

Figure 5. U.S. Average Fuel Prices

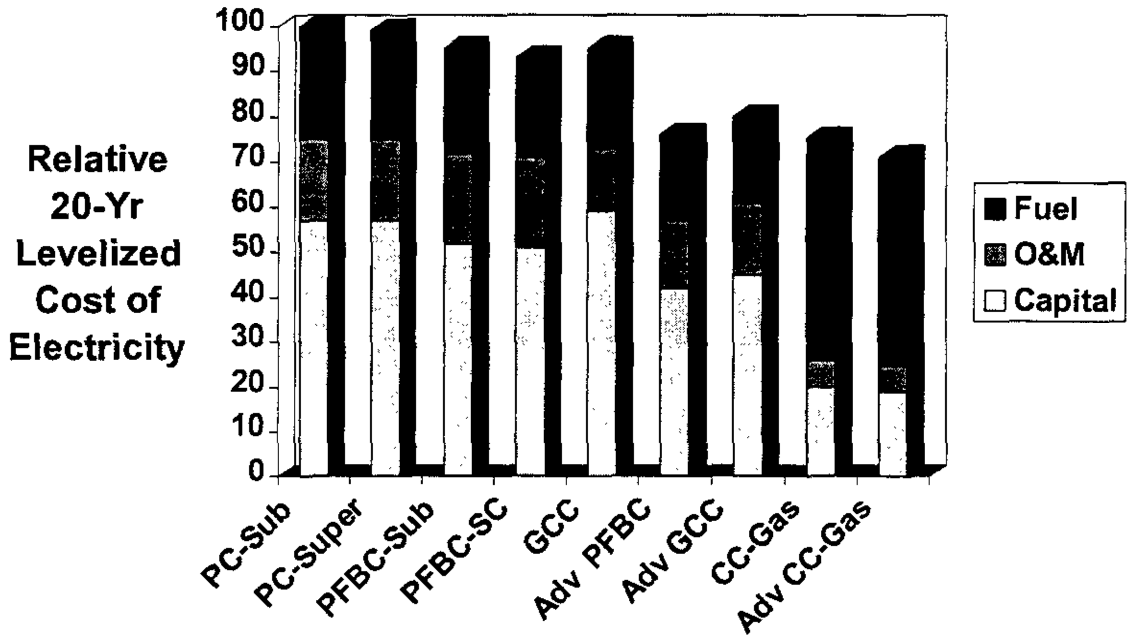

Figure 6. Cost of Electricity Comparison (Year 2000 Startup)

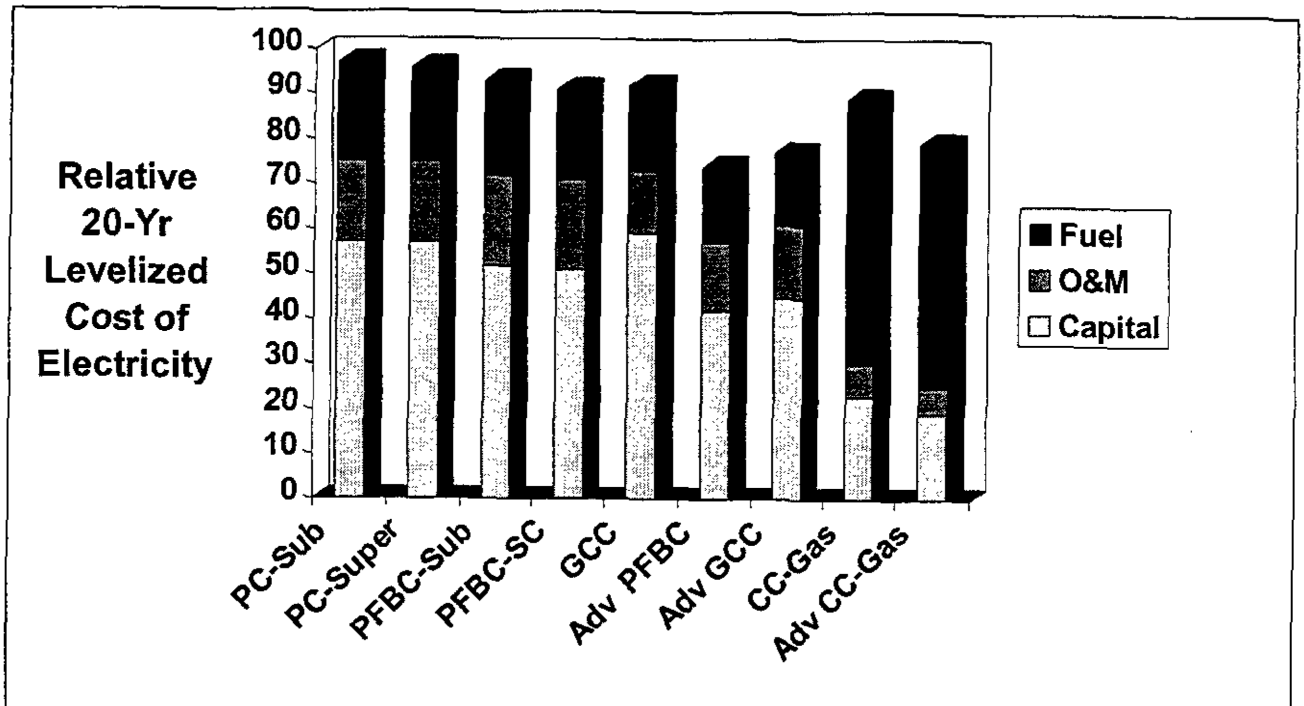

Figure 7. Cost of Electricity Comparison (Year 2010 Startup)

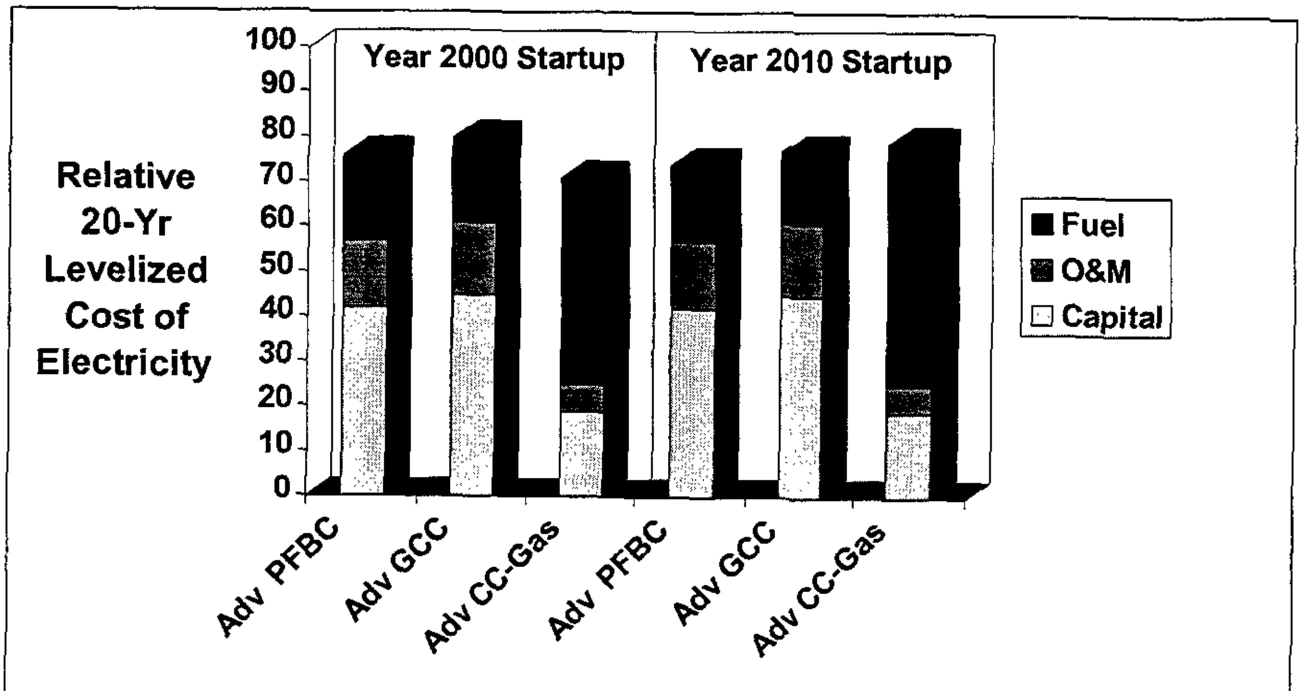

Figure 8. Cost of Electricity for Advanced Coal and Gas Technologies

MERCHANT COAL PLANTS?

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ABSTRACT

As the electric utility industry undergoes deregulation, the need for new generating plants will be indicated by market prices rather than traditional planning methods. The selection of fuels, technologies and other factors can significantly affect the near term and long term success for investors. Solid fuels such as coal have carried the bulk of electric generation producing over half of the electricity produced today. However, new plants announced have predominantly been natural gas fueled using combined cycle, simple cycle or cogeneration.

This paper will review criteria typically evaluated by developers of new independent power plants. The focus will be on factors that will suggest that coal fired plants are competitive with natural gas plants.

I. INTRODUCTION

This paper is presented in conjunction with the Department of Energy's 7th Clean Coal Technology Conference. The competitiveness of coal fired projects for meeting replacement and expanding electric energy needs is examined from a developer's perspective. The primary market focus is the United States. The Public Utilities Regulatory Policy Act of 1978 (PURPA), the Energy Policy Act of 1992 and continued state by state deregulation of the electric utility industry presents opportunities for the development of new unregulated sources of electricity and other forms of energy. Unregulated in this case means projects not subject to the Public Utility Holding Company Act (PUHCA). All fuels and technologies are increasingly allowed to compete in an open market for the right to serve new energy needs or even displace existing energy providers.

The Department of Energy's (DOE) Clean Coal Technology Program has stimulated the development and commercial demonstration of technologies that can utilize the enormous coal reserves in the United States while complying with strict environmental emissions requirements. Meeting environmental regulations is mandatory, but coal technologies must also prove to be economically competitive with alternative technologies and fuels. The low cost producer must address fuel, operating and capital costs. Investors will seek a return "of" and "on" their funds commensurate with the business risk.

II. BACKGROUND

Duke Power and now Duke Energy has a long tradition of owning and operating successful coal fired plants. Many of Duke's 30 regulated coal plants built in the 1960's and 1970's embraced fuel efficiency through nationally recognized heat rates in the 9000 Btu per kilowatt hour range. Also, Duke historically selected lower sulfur coals as a way to minimize SO_2 emissions and reduce stack maintenance.

Duke's initial unregulated Independent Power Projects (IPP) evolved from this coal fired experience. Under PURPA, in 1986 Duke participated in the design, construction and ownership of a QF Circulating Fluidized Bed (CFB) cogeneration project near Watertown, New York. Electricity was initially sold to Niagara Mohawk Power Company under a long term power purchase agreement on a take-if-tendered basis. Rates were established by the State of New York at $0.06 per kilowatt hour to promote cogeneration and mitigate even higher projected costs. This long term agreement was terminated due to declining electricity prices and surplus capacity. The project currently sells power on the wholesale electric market in New York. Thermal energy is sold to the Fort Drum Army Base for district heating. This project is able to achieve excellent levels of environmental compliance for NO_x and SO_2, while using multiple fuel sources. Bituminous coal, anthracite coal and wood (10%) are acceptable fuels. Recently, petroleum coke has been successfully burned in the CFB boilers.

Under PURPA, in 1989 Duke participated in a QF Pulverized Coal (PC) cogeneration plant located in Mecklenburg County, Virginia. Virginia Electric and Power Company selected this project as part of a competitive bidding process for new capacity and signed a long term power purchase agreement. Steam is sold to a nearby textile plant. This project uses advanced burners with overfire air to control NO_x and lime scrubbing to control SO_2. The fuel is a typical eastern utility grade bituminous coal. At the time of permitting this plant advanced the limits of commercially proven NO_x burner control equipment.

In 1992 Duke became interested in Integrated Coal Gasification Combined Cycle (IGCC) technology. This technology offers significantly superior environmental compliance as well as improved thermal efficiency. Fuel flexibility is also enhanced because the environmental contaminants are removed prior to combustion of the syngas produced in the gasification process. Post combustion technologies also effectively remove the contaminants, but tend to reduce net plant efficiency as well. However, the benefits of low environmental emissions, better efficiency and fuel flexibility are achieved with an increase in capital costs. The IGCC project was selected as part of the DOE's Clean Coal Technology Round V.

Those projects representing pulverized coal boiler, circulating fluidized bed boiler and integrated coal gasification combined cycle technologies represent a range of commercially viable solid fuel technologies being evaluated in today's market. They are able to comply with strict environmental requirements and sustained reliability. However, they must also compete against alternative fuels and technologies.

III. PROJECT DEVELOPMENT

Privately owned (non-regulated) cogeneration and small power producer projects have been successfully developed, owned and operated since PURPA was passed in 1978. These early projects tended to emphasize efficiency (electric and thermal) or low cost waste fuel resources. Electric energy and capacity are sold to a regulated utility where the sales price is less than the utility's calculated avoided cost and additional capacity is needed. Public Utility Commissions allow this cost of service to be passed through to retail customers under regulated electric rate schedules.

The Energy Policy Act of 1992 opened the door for exempt wholesale generating (EWG) projects to sell directly to the wholesale market as merchant energy plants. Access to the wholesale transmission system was affirmed under FERC Order 888. EWGs were allowed to compete with regulated utilities and sell to regulated utilities, but only in the wholesale market. The market price, rather than the calculated utility avoided cost, became the standard that determined the economic success of the project.

Today, private companies are allowed to compete with regulated utilities for sales of wholesale power. The development of coal fired EWG projects lags behind an explosion of natural gas fueled EWG projects. In the case of a non-regulated QF or EWG project, the developer's basic job is to analyze the "risks" and "rewards" associated with the project. The rewards must be adequate to attract debt and equity over the expected life of the project. Investors need to carefully evaluate the economic risks against potential economic rewards. The transition of the electric industry from a regulated cost of service to a commodity priced business dramatically alters the business risks that must be managed.

Major Business Risk Shifts

Regulated Service	EWG Merchant Plants
Guaranteed regulated return on investment	Return determined by market prices
Predictable revenue	Volatile revenue
Recoverable fuel costs	Fuel cost related to market price
Reliability driven	Cost driven

In a regulated environment all customers have access to reliable electricity at reasonable prices. The Public Utility Commission is charged with determining if the final price is reasonable and if costs are prudent. The cost of capacity, including reserve capacity, is recognized as needed and recovered over time through approved tariffs. Operating and fuel costs are also reviewed and ultimately passed on to the final consumer.

In a deregulated environment, the market price is the primary determining factor. Projects offering low variable operating costs are operated first in order to offer the lowest cost to the customers. But, there are no assurances that the market price will adequately cover a project's variable operating and fixed costs. Some of the un-recovered costs could be stranded by the market price to the dismay of investors. However, markets may also significantly reward project owners with higher prices when electric supplies are limited. In 1998 spot electric prices exceeded $5000 per MWhr when hot summer temperatures arrived a month early in the Mid-America Interconnected Network (MAIN).

Market based prices are dynamic. They adjust quickly to changes in energy supply and demand, fuel price changes, new or missing capacity and simply from swings in weather conditions. New investments are made subject to forecasts of future market price ranges.

Major Risks

Lenders and investors have learned to carefully examine the business risks associated with each project. The basic risks that need to be addressed during project development are fairly consistent. However, the market is continuing to evolve; and much can change in twenty years, especially as the electric business transitions from a cost of service to a commodity priced market. Project risks are often grouped into 3 major areas:

1. Development
2. Construction/ Startup
3. Operation

Development Risks

Siting
Transmission access
Fuel supplies
Environmental permitting: air, water, land
Project capital cost
Contracting
Financing
Interest rates

Construction/ Startup Risks

Capital cost
Schedule
Performance: capacity, heat rate
Environmental compliance

Operating Risks

Revenue: selling price (energy and capacity)
Variable expenses: fuel availability and price, O&M
Fixed expenses: O&M staff, taxes, G&A
Reliability
Thermal efficiency
Change in Law: EPA, Kyoto, etc

These risks are evaluated both individually and as a group for consistency for each project. Predictable revenues with well managed expenses combine to create attractive projects for investors.

Revenue

Revenue is the most important determinant for the success of any project. Project expenses must fit underneath this envelope. In a commodity electric market, all forms of fuels and technologies are allowed to compete. Electric supply and demand also significantly affect price. Reserve margins are subject to wide variations at a point in time due to new capacity, retirements, scheduled outages and forced outages. Companies are working diligently to examine and forecast a range of future energy prices. This work is part science and part art. A great deal of judgement is needed to make informed decisions when investing in new projects.

Market Price Estimate or Forward Price Curve

Dispatch Price
- Variable fuel cost (also limestone, ammonia, ash disposal, etc)
- Variable O&M costs
- Startup costs

Supply/ Demand (Reserve Margin)
- Capacity
- Fixed O&M

Existing plants, new plants, plant retirements and changing fuel costs affect the shape of the forward price curve.

Reward

The reward available to the investor is simply revenues earned by the project minus the variable and fixed operating expenses.

Market Revenue (-) Operating Expenses (=) Investor Reward

While this is a simple concept in theory, the commitment of funds to build a merchant plant is subject to detailed analysis and review.

IV. COAL VERSUS NATURAL GAS

Under regulated rules, the price of power or revenue required for the business on an annual basis is determined by summing the fixed capital charge, the fixed operating cost and the variable operating cost. The fixed charge includes depreciation, financing costs plus a return for the utility investor. The fixed operating costs included staff, taxes, insurance and corporate overheads. The variable cost is essentially fuel cost. Rate tariffs are adjusted up or down via rate cases to achieve the necessary revenue.

In a deregulated energy market, revenue is determined by the market either on a spot or long term contract basis. By starting with an estimate of the market revenues available, alternative technologies and fuels can be compared for competitiveness.

Market Revenue (-) Variable and Fixed Operating Costs (=) Market Implied Capacity Value

As a simple example, a coal project with the following assumptions can demonstrates this concept:

- $1200 per kW for all in capital cost
- 10,000 Btu per kWhr heat rate
- $1.50 per million Btu fuel cost
- $5.00 per MWhr operating cost

and a natural gas combined cycle (NGCC) plant with the following assumptions:

- $600 per kW for all in capital cost
- 7000 Btu per kWhr heat rate
- $2.50 per million Btu fuel cost
- $4.00 per MWhr operating cost.

To achieve a return for the investor, a fixed charge rate of 15% which results in approximately $10.00 per MWhr revenue at 100% capacity factor (CF) is assumed.

In comparison:

	Coal: $/MWhr	NGCC: $/MWhr
Fuel: Cost x Heat Rate	$15.00	$17.50
O&M	$5.00	$4.00
Capital @100 % CF	$20.00	$10.00
Total	$40.00	$31.50
Total @ 50% CF	$60.00	$41.50

These results suggest that while coal enjoys a lower delivered fuel cost, this advantage is mitigated by a higher heat rate. The lower NGCC heat rate significantly offsets the higher natural gas price. The significant competitive disadvantage of a coal versus a natural gas project lies in the initial capital cost. Fuel savings are not adequate to cover the higher capital costs.

Per the above example, a NGCC plant with only a fifty percent capacity factor can compete with a base load coal plant. Of course $40.00 per MWhr power is not available year round, but is more representative of intermediate and peak pricing. Minimum pricing for operating a plant should recover variable fuel and often includes variable operating costs. From the example above, the variable pricing could range from $15.00 per MWhr for variable coal costs to $21.50 per MWhr for the NGCC fuel and operating costs. This is very consistent with published off peak pricing, when adequate capacity is available to meet all customers energy needs.

Coal Project Disadvantages

Total cost provides a composite comparison of the competitiveness of a fuel and technology, but does not provide insight regarding the risks that must be managed. Other coal plant disadvantages include:

- Permitting risks for schedule and allowed emissions levels
- Initial capital risk over twice that of a natural gas combined cycle plant
- Construction schedules which take a year or more longer than natural gas plants
- Start-up and shake-down risks
- Fuel inventory costs and storage issues
- Higher property taxes and insurance due to higher capital costs
- Higher financing costs associated with interest rate risk and IDC
- Higher sustained capacity factors needed to produce revenue

Market Disadvantages for Coal

Where natural gas is available, combined and simple cycle projects are strong competitors. Some of the market disadvantages for coal projects are:

- Deregulation favors less capital intensive projects
- Slower response to market price signals for new capacity
- Environmental change in law including Kyoto
- Base load nuclear, coal and QF capacity dominate many markets
- Heat rate gap is growing

V. COMPETITIVE COAL PROJECTS

Coal-fueled projects provide over fifty percent of the electric energy produced today. Coal plants that are running reliably will continue to offer competitively priced electricity. However, over time these plants will shut down due to age, lack of environmental compliance or high operating costs. When will the market signal that coal plants can be competitive again? All other factors being constant, coal's competitiveness would improve under the following conditions:

- Natural gas cost exceeds coal by over $2.00 per MMBtu
- Combined cycle capital or maintenance costs increase significantly
- Natural gas is not available
- Large capacity shortfalls occur in the market due to nuclear retirements
- Large base load energy users seek long-term price stability or alternate energy like steam
- IGCC providing complementary value such as chemicals or solid waste disposal

Developers will once again embrace solid fuel or coal technologies when the risk and reward profile compared to alternative forms of energy are reasonable. Lower capital costs, higher efficiencies, lower fuel costs and high reliability improve and ultimately determine the competitiveness of these solid fuel technologies.

OPTIONS AND COSTS FOR CO_2 REDUCTION AT COAL-BURNING POWER PLANTS

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ABSTRACT

The power generation industry may be required to reduce CO_2 emissions if regulations related to carbon dioxide emissions are enacted. Coal-fired generation, which emits 82% of the power sector CO_2, would be a likely target for CO_2 reduction. Compliance with the Kyoto protocol, for example, would require a 30% reduction in CO_2 emissions from the projected year 2012 level even with moderate load growth. This paper describes an analysis of power industry CO_2 reduction options and their costs to assess how a generator would make compliance decisions under a mandatory CO_2 emissions reduction requirement. Carbon sequestration, fuel switching and new plant construction are considered. The compliance options are ranked in terms of the cost of electricity for a given level of CO_2 reduction.

I INTRODUCTION

The Global Climate Change Treaty signed at the Rio de Janeiro Earth Summit in June 1992 established the long-term goal of stabilizing greenhouse gas concentrations in the atmosphere. The December 1997 Kyoto Protocol established short-term mandatory targets for the United States and 37 other developed countries (the "Annex I" countries). The United States is to reduce greenhouse gas emissions by 7% compared to the 1990 emission level by year 2012. Developing countries are exempt from reduction requirements under the Kyoto Protocol despite projections indicating that significant increases can be expected in their emission levels. Because the Kyoto Protocol must be ratified by the U.S. Senate to become legally binding in the U.S., it's effect as a policy instrument is problematic. However, it is used here as an basis for analyzing what operators of coal-fired generating units might do if CO_2 emission reductions are required in the future.

U.S. power industry carbon emissions were 490 million tonnes in 1990 and are projected to be 647 million tonnes in 2012 according to the Energy Information Administration of the U.S. DOE (Annual Energy Outlook 1997). Coal-fired generation emits 82% of the power sector CO_2. Assuming that the power industry is required to do only a proportional share, the 30% emission reduction required by the Kyoto Protocol would equate to a reduction (or sequestration) of 191 million tonnes of carbon emissions from coal-fired power plants. Meeting the longer term goal of the Rio Treaty to stabilize the atmospheric CO_2 concentration and stop global warming would require large, additional emission reductions.

II EVALUATION BASIS

CONSOL R&D developed a power industry CO_2 compliance analysis to give a utility-eye view of the compliance decision process under a mandatory greenhouse gas emissions reduction program. The study is a single plant comparison of baseload power plants in the Northeast Region, a key market sector for many coal companies. Carbon sequestration, fuel switching at existing plants, and new plant construction options were evaluated. Project financing assumptions were based on a deregulated power industry environment. The financial factors, which require a higher return on capital and a shorter project life, favor the lower capital cost and shorter construction period of new gas-fired plants. All plants were evaluated at an 85% capacity factor, which represents the anticipated higher utilization of generating assets under deregulation. All costs are in 1997 dollars.

Two fuel price scenarios were evaluated. The current fuel price case assumes that both coal and gas prices will remain at current levels in real terms. The average current delivered prices of coal and gas in the Northeast Region are $1.45/GJ and $2.60/GJ ($1.54 and $2.74 per million Btu), respectively. The high gas price case assumes that wholesale replacement of nuclear and coal-fired power plants with gas-fired plants increases the year-around demand for gas significantly and drives up the cost in real terms to $4.74/GJ ($5.00 per million Btu).

III OPTIONS EVALUATED

Options to reduce CO_2 emissions include fuel switching to gas in existing plants and plant replacement with new plant. In addition to emission reduction, sequestration may be required either as an offset (indirect sequestration) or in conjunction with emission reduction (direct sequestration). Power generation performance, CO_2 emissions/emission reductions, and power costs are shown in Table 1 for the non-sequestration options and in Table 2 for the sequestration options. The performance of each plant was evaluated on a higher heating value basis and at site (i.e., non-ISO) conditions. The emission level of each plant is a combination of plant performance and the inherent emissions of the fuel. Here, natural gas has a significant advantage over coal. The CO_2 emission level of gas is 240 kg/GJ (115 lb per million Btu) while the emission level of a high quality bituminous coal is 420 kg/GJ (201 lb per million Btu).

Existing Plant

The Existing Pulverized Coal (PC) plant in Table 1 represents the average of all pulverized coal-fired utility plants in the Northeast Region. This plant has a smaller capacity and lower efficiency than today's standards, but is representative of the vintage of PC plants currently in service. The existing PC plant is used as the base case for evaluating the emission reduction options.

Fuel switching from coal to natural gas in the existing PC is a low capital cost option to reduce CO_2 emissions (per unit electricity generated) by 39% from the base case. Net power output is increased slightly because of a reduction in auxiliary power requirements for coal handling, grinding, particulate control and ash handling. The net heat rate increases because of the decrease in boiler efficiency associated with the formation of water during combustion. The savings in non-fuel operating and maintenance (O&M) costs do not offset the significantly higher fuel cost.

New Plant Options

Advanced PC: The Advanced PC plant represents a pulverized coal plant design using an ultrasupercritical steam cycle. Demonstration projects of this type of plant are currently underway in Japan and Denmark. The ultrasupercritical PC has an advantage over lower pressure/temperature subcritical and supercritical PC plants (which are not included in this analysis) of a lower heat rate and lower emissions at a similar capital cost and power cost. The advanced PC plant includes flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems as required under New Source Performance Standards (NSPS).

The advanced PC plant has a lower fuel cost than the base case plant, but has a higher non-fuel O&M cost because of FGD and SCR-related costs. The capital charge represents about one-half of the total power cost. The advanced PC plant reduces CO_2 emissions by 11% from the base case.

CCT Plants: The current Clean Coal Technology (CCT) plant is representative of the first generation Integrated Gasification Combined Cycle (IGCC) plant being demonstrated under the CCT program. The current CCT plant has a lower heat rate and emission level than the PC plants but has a high capital cost and a high non-fuel O&M cost. The current CCT plant reduces CO_2 emissions by 16% from the base case.

The advanced CCT plant represents the second generation IGCC or Pressurized Fluidized Bed Combustion (PFBC) plants now under develppment. The target of these programs is to improve generating efficiency while reducing capital costs through design simplification, advancements in materials, and operating experience.

The advanced CCT plant represents a significant performance advancement from all other coal-fired options and has the lowest capital cost of the new coal-fired plants. The advanced CCT plant reduces CO_2 emissions by 23% from the base case.

Co-Production: The co-production plant uses a combination of coal and natural gas to produce liquid products and power via coal gasification, syngas production, and combined cycle power generation. This plant uses a fuel mix of 60% gas and 40% coal. The combined effects of natural gas use, an advanced power cycle and carbon credited from the production of liquid products reduce emissions by 45% from the base case. Revenue from the sale of liquid products offsets the capital cost and higher fuel cost of gas.

GCC: The Gas Combined Cycle (GCC) plant represents the current state-of-the-art G-frame gas turbine GCC plant. For high capacity factor baseload service, this plant is equipped with dual fuel (gas and oil) capability. The performance of the plant is somewhat poorer than that of generally published values which are based on International Standards Organization (ISO) conditions (sea level and 60°F) and the lower heating value of natural gas. CO_2 emissions are reduced by 59% from the base case. This plant has the lowest capital cost and non-fuel cost of any new plant option evaluated. *The fuel cost is three-fifths of the power cost at the current gas price and two-thirds of* the power cost at the high gas price.

Sequestration

Two types of carbon sequestration are evaluated; forestation (indirect) and technological (direct) sequestration.

Forestation sequestration in conjunction with the continued use of existing coal-fired PC plants allows the emissions to be offset while avoiding new plant construction costs. The scenario shown here represents the cost of a domestic forestation program (adapted from Richards et al., 1993) and assumes that the power sector reduction level is limited to 25% because of competition with other industries seeking to minimize their compliance cost. The forestation cost reflects a mid-range land use cost imposed by landowners, the cost of removing agricultural land from service, the need to use more marginal land and updated, lower sequestration rates.

Technological sequestration consisting of CO_2 removal, compression, pipeline transport and deep ocean disposal (adapted from Smeltzer and Booras, 1990) is examined as a retrofit to the existing PC plant (avoiding new plant construction) and integrated into an advanced CCT plant. Technological sequestration reduces emissions by 90-93% but has a high capital cost, high fuel and non-fuel O&M costs. Plant performance is impaired because of auxiliary power and steam requirements.

IV COMPLIANCE ANALYSIS

Figure 1 illustrates the compliance analysis at the current fuel prices. Without CO_2 restrictions, the analysis would be one-dimensional and power cost would be the determining factor for choosing fuel and generating plant type. With mandatory caps, however, compliance decisions have the dual objectives of reducing emissions while minimizing the increase in power cost. The least cost compliance path reduces the emission level from the existing plant to a lower level at the smallest increase in power cost. The slope of the line is the CO_2 reduction cost, in units of \$/tonne CO_2.

In general, emission reductions will result in significant increases in the cost of electricity to the American public. Forestation sequestration, the least expensive option, increases the power cost from existing coal-fired plants by 22%. Fuel switching or new plant construction increases the power cost by 60-150%. Technological sequestration increases the power cost by 200-300%.

In this analysis, the continued use of existing coal-fired plants while implementing forestation sequestration is the lowest cost option for reducing emissions from the current level. Non-domestic forestation may offer the potential for additional reductions and a lower cost, but was not considered explicitly in this analysis.

At current fuel prices, emission reductions beyond what can be achieved by forestation will be met by the construction of new natural gas combined cycle, or GCC plants. Pulverized coal and current Clean Coal Technology plants have the highest power costs and achieve the smallest emission reduction. Next-generation, advanced Clean Coal Technology plants offer significant emission reductions and the power cost of the advanced CCT unit is competitive with power costs of the GCC plants. However, the advanced CCT unit does not achieve the emission level as the gas-fired plant. GCC is preferred over fuel switching (i.e., from coal to gas at existing PC units) even at the current gas price because its greater power generation efficiency more than offsets the higher capital cost and results in significantly lower emissions at the same power cost. Co-production of power and liquid products using coal and natural gas fuels could be an attractive option for preserving some coal in the fuel mix but is heavily dependent on liquid product prices. In this analysis, liquid product sales reduce the power cost by 23%.

Technological sequestration is the ultimate in emissions reduction but the cost is very high and a great many technical, political, environmental, and cost uncertainties exist regarding deep ocean or inland disposal. The compliance path shows that advanced Clean Coal Technology plants combined with technological sequestration are an option if emission reductions beyond what can be achieved with GCC plants are required. Integrating CO_2 removal technologies into high-efficiency advanced coal plants is much more cost-effective than retrofitting them onto lower-efficiency existing PC plants.

Figure 2 shows the compliance path analysis at the high gas price. It illustrates the risk of over-reliance on gas for emissions compliance. Once again, forestation is the lowest cost first step in reducing emissions. Now, however, the price of natural gas has increased to a point where the advanced Clean Coal Technology plant with technological sequestration is a more cost-effective emission control option than the GCC plant. Meeting the short-term target with gas would have resulted in a higher compliance cost in the long run.

The dashed line in Figure 2 is the least cost technology path in the absence of indirect sequestration. It illustrates that advanced CCT plants can play an important role in coal's future if offset options are limited, and gas prices respond to the higher anticipated consumption level. The challenge is to accelerate the development of even more efficient, lower cost technologies so that coal has the opportunity to compete with gas in the near term as well as in the future.

V CONCLUSIONS

The conclusions to the study are the following:

- Implementation of a carbon reduction program like that of the Kyoto Protocol will increase electricity costs substantially. Depending on the level of reduction required, power cost increases of 200-300% are possible. Moreover, even this level of cost increase assumes technological advances, turnover of generating equipment, and natural gas prices and availability that are uncertain at best. Carbon reduction programs must be proven beyond a doubt to be necessary and must be implemented fairly worldwide.

- *Forestation sequestration* is the lowest cost emission reduction option because it allows the continued use of existing coal-fired power plants and avoids the high cost of new plant construction and use of a more expensive fuel. Meeting the near-term carbon reduction target with forestation also allows time for development of lower cost and more efficient carbon management alternatives to achieve long-term goals. Forestation could be limited (particularly in the U.S.) because of the intensive land requirements of this sequestration option.

- High efficiency GCC plants can reduce CO_2 emissions significantly and would be the option of choice if gas price stability and gas availability can be assured over the long term.

- Without a competitive fuel mix, over-reliance on natural gas for power generation will result in a high gas price and a higher compliance cost in the long term.

- Advanced Clean Coal Technology and co-production plants, which piggyback on the advancements in gas turbine technology, will be preferred over pulverized coal plants in the future, if current development programs are able to deliver on the promise of higher efficiency and lower capital costs. These technologies will help to ensure that low-cost coal remains available as the fuel of choice for electric power production in the future.

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TABLE 1
Power Generation Technology Performance and Cost Comparison

Unit Type	PC	PC	GCC (G)	Adv PC	Current CCT	Adv CCT	CoCo-High Gas
Plant Status	Existing	Existing	New	New	New	Conceptual	Conceptual
Fuel	Coal	Gas	Gas	Coal	Coal	Coal	Coal & Gas
Steam Conditions	Subcrit.	Subcrit.	Subcrit.	Ultra Supcrit.	Subcrit.	Subcrit.	Subcrit.
FGD	No	No	No	Yes	No	No	No
SCR	No	No	No	Yes	No	No	No
Plant Performance							
Size, MW	242.7	242.7	332.4	530.0	227.0	424.4	449.8
Net Output, MW	231.5	233.4	322.4	503.0	214.0	400.0	425.9
Net Heat Rate, Btu/kWh	9,711	10,352	7,009	8,679	8,106	7,500	8,885
Efficiency, %	35%	33%	49%	39%	42%	46%	38%
Liquid Output, Bbl/day	0	0	0	0	0	0	3,041
Capacity Factor, %	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Generation, GWh/yr	1,724	1,738	2,401	3,745	1,593	2,978	3,171
Coal Fuel Use, MM Btu/hr	2,248	0	0	4,365	1,734	3,000	1,634
Gas Fuel Use, MM Btu/hr	0	2,416	2,260	0	0	0	2,150
Total Fuel Use, MM Btu/hr	2,248	2,416	2,260	4,365	1,734	3,000	3,784
Emissions/Reduction							
CO2 Emissions, st CO2/GWh (1)	977	596	403	873	815	754	532
CO2 Reduction, %	Base	39.0%	58.7%	10.6%	16.5%	22.8%	45.5%
Capital							
Plant Cost, $/net kW (2)	$0	$5	$624	$1,023	$1,392	$900	$1,072
Results At Current Fuel Price							
Fuel Cost, $/MM Btu (3)	$1.53	$2.74	$2.74	$1.53	$1.53	$1.53	$3.50
Levelized Power Costs, mils/kWh							
Capital	0.00	0.09	11.00	20.74	28.20	18.24	16.47
Fixed O&M	3.44	2.91	1.86	3.17	5.18	3.35	3.09
Variable O&M	0.80	0.38	0.29	2.30	1.56	1.44	1.00
Fuel	14.84	28.36	19.21	13.24	12.39	11.46	18.54
Liquid Product Sales (4)	0.00	0.00	0.00	0.00	0.00	0.00	(8.93)
Total Power Cost	19.07	31.74	32.35	39.44	47.33	34.49	30.17
Reduction Cost, $/ton CO2	0	$33	$23	$196	$175	$69	$25
Reduction Cost, $/tonne C	0	$134	$94	$792	$707	$280	$101
Results At High Gas Price							
Fuel Cost, $/MM Btu (3)	$1.53	$5.00	$5.00	$1.53	$1.53	$1.53	$2.22
Levelized Power Costs, mils/kWh							
Capital	0.00	0.09	11.00	20.74	28.20	18.24	16.47
Fixed O&M	3.44	2.91	1.86	3.17	5.18	3.35	3.09
Variable O&M	0.80	0.38	0.29	2.30	1.56	1.44	1.00
Fuel	14.84	51.76	35.05	13.24	12.39	11.46	29.27
Liquid Product Sales (4)	0.00	0.00	0.00	0.00	0.00	0.00	(8.93)
Total Power Cost	19.07	55.14	48.19	39.44	47.33	34.49	40.91
Reduction Cost, $/ton CO2	0	$95	$51	$196	$175	$69	$49
Reduction Cost, $/tonne C	0	$383	$205	$792	$707	$280	$198

1. CoCo process is credited with 24 MM tons of carbon per quad of liquid produced which is tne emission of liquid fuels from crude.
2. Includes direct, indirect costs and a contingency. Does not include other owners costs and replacement equipment.
3. CoCo fuel price is a weighted price based on fuel mix and the price of coal and natural gas.
4. Liquid byproduct price is $30/bbl based on a crude oil price of $21/bbl.

TABLE 2
Sequestration Performance & Costs
(All Cases)

Unit Type	PC	Adv Coal	PC
Plant Status	Existing	Conceptual	Existing
Fuel	Coal	Coal	Coal
Sequestration Method	Technology	Technology	Forestation
Steam Conditions	Subcrit.	Subcrit.	Subcrit.
FGD	Yes	No	No
SCR	No	No	Yes
Performance ex Removal /Disposal			
Size, Mw	242.7	424.4	242.7
Net Output, MW	228.0	400.0	228.0
Net Heat Rate, Btu/kWh	9,859	7,500	9,859
Capacity Factor, %	85.00%	85.00%	85.00%
Generation, GWh/yr	1,698	2,978	1,698
Fuel Use, MM Btu/hr	2,248	3,000	2,248
Performance inc. Removal /Disposal			
Capacity Loss, % (2)	35.29%	12.00%	0.00%
Net Output, MW	147.5	352.0	228.0
Net Heat Rate, Btu/kWh	15,236	9,290	9,859
Efficiency, %	22%	37%	35%
Generation, GWh/yr	1,099	2,621	1,698
Fuel Use, MM Btu/hr	2,248	3,270	2,248
Emissions/Reduction			
CO2 Removal Efficiency, %	93.3%	90.0%	25.0%
CO2 Emissions, tons CO2/GWh	101	93	732
CO2 Reduction from Exist Plant, %	89.6%	90.4%	25.0%
Capital			
Plant Cost, $/net kW	$0	$900	$0
CO2 Removal/Disposal, $/net kW			
Plant Modifications (1)	$458	$98	$0
CO2 Removal	$358	$43	$0
Compression	$130	$91	$0
Pipeline and Disposal	$641	$609	$0
Subtotal Removal/Disposal	$1,588	$841	$0
Total Cost with Removal/Disposal	$1,588	$1,741	$0
Results			
Fuel Cost, $/MM Btu	$1.53	$1.53	$1.53
Levelized Power Costs, mils/kWh			
Capital	32.18	35.29	0.00
Fixed O&M	14.98	5.64	3.44
Variable O&M	7.26	2.79	0.80
Forestation Equivalent Cost (3)	0.00	0.00	4.22
Fuel	22.93	14.20	14.84
Total Power Cost	77.36	57.92	23.29
Reduction Cost, $/ton CO2	$67	$44	$17
Reduction Cost, $/tonne C	$269	$178	$70

1. Plant modifications for existing plant includes an FGD system.
2. Reflects steam diverted for CO2 removal and aux power for power generation and CO2 sequestration.
3. Mid-range estimate for land use discount rate.

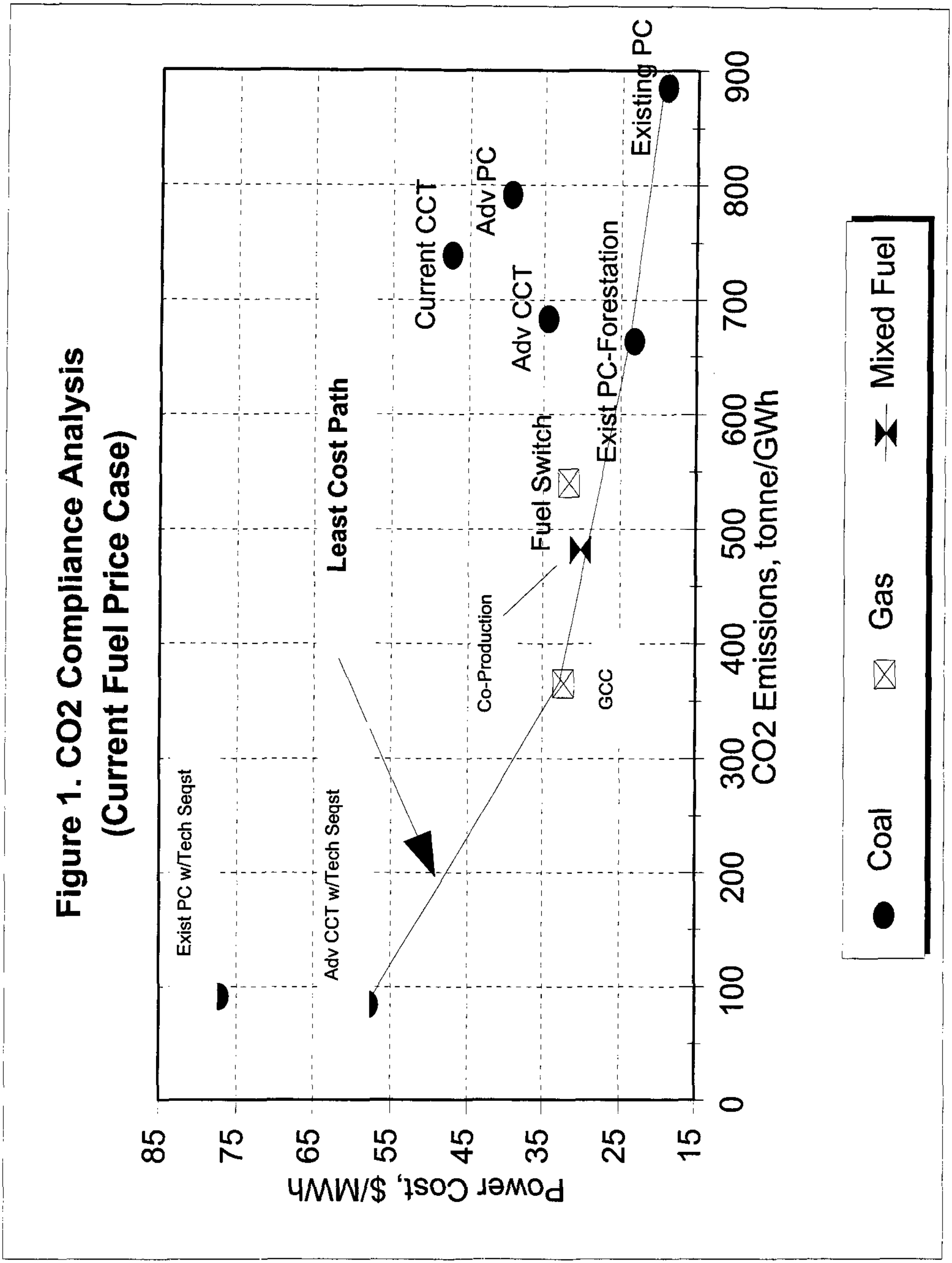
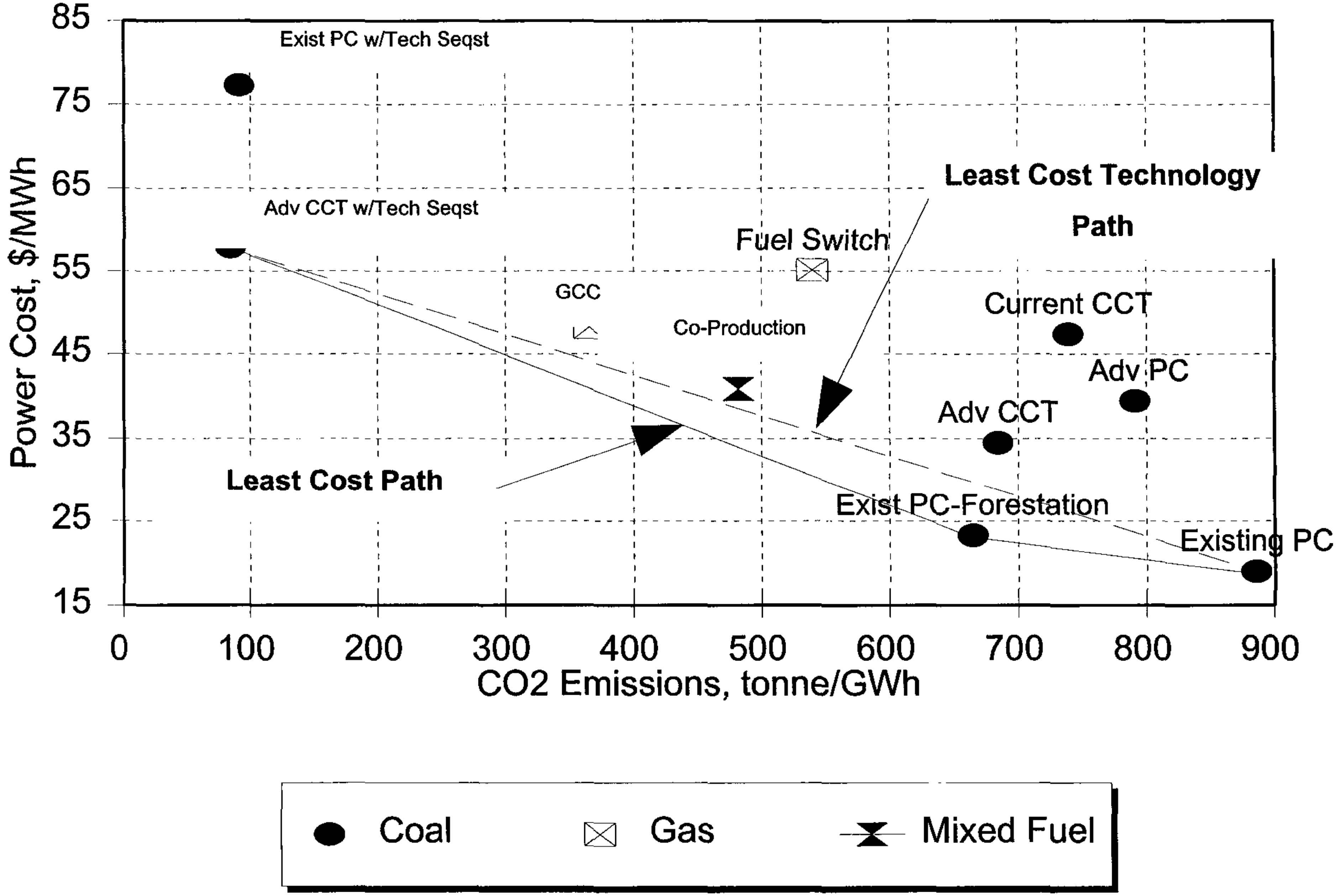


Figure 1. CO2 Compliance Analysis (Current Fuel Price Case)

Figure 2. CO2 Compliance Analysis (High Gas Price Case)



DISCUSSION OF INCENTIVES THAT CAN BE INTRODUCED TO REMOVE BARRIERS

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UNAVAILABLE AT TIME OF PRINTING

PANEL SESSION 2

Issue 2: Global Community Responsibility–Role of Technology and Project Developers, Financiers, Consumers and Governments

DEVELOPING COUNTRIES IN THE GLOBAL COMMUNITY RESPONSIBILITY

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ABSTRACT

From the current 6 billion people the world population is expected to reach 8 billion by the year 2020 and 10 by 2050, and it is estimated that 90% of this population explosion will occur in developing countries. The rise from the 1990 level of global energy demand (9Gtoe) is around 7Gtoe by 2020, of which the developing countries account for 6 Gtoe. Much of the demand expansion will be supplied by fossil fuels.

Everybody wants what is commonly known as sustainable development, but how can this be achieved if developing countries don't have the necessary means and industrialized countries are not inclined to help on a satisfactory scale.

Market globalization has benefited industrialized countries in detriment to those in development.

According to the World Energy Council, the problem of poverty persists. Today, one-third of the world population does not have access to commercial forms of energy while 20% of it consumes 80% of energy production. Too little progress has been made in addressing those needs. In rural areas the problem is particularly acute and new partnerships and economic models are needed to tackle it.

Is industry in developed countries really ready to increase its costs to assure the survival of Planet Earth by taking the responsibility for cutting down on the emission of gases that cause the greenhouse effect and by passing on their knowledge of clean technology to developing countries? Or will the stock market bull effect always take precedence over these issues?

When will it be possible to equate company profits with efficacious government action for the well being of all peoples?

I. INTRODUCTION

Accumulation of capital by the private sector, significant progress in telecommunications, rapid advances in new technologies, as well as the end of the so-called cold war speeded up what is today referred to as market globalization.

Unfortunately this has been a process in which the industrialized countries are the only winners. The rules of the game are stringent and irrevocable and, what is worse, if you don't want to play you are ostracized.

The power of governments is shrinking. They increasingly give way to market forces and that is placing the world into a confrontation that is both dangerous and undesirable.

History is known to repeats itself and wars are more likely to act as an escape valve when social conflicts become intolerable. And what do we see today? Wars being waged in all five continents of our planet.

Globalization per se does not necessarily lead to battles; wars result more and more frequently when forces of the transnational economy continuously make little of social aspects, although these should be as important a factor in trade relations as they now are in environmental questions. Worldwide unemployment is the other sad visible issue of this situation. Yet the political answers to the globalization of the economy do not point to any action taken for reducing its negative impacts.

Last year was the 50th anniversary of The International Declaration of Human Rights. It should be stressed that not only civil and political rights, but also rights of an economic and social nature are included in this Declaration. It states in its introduction that Man's highest aspiration is freedom from the fear of penury.

I most certainly do not consider myself a prophet of Judgment Day. I have no doubt, however, that our civilization and our culture will fail if we don't immediately establish and apply measures that will allow the two billion human beings who, according to the World Energy Council (WEC) have no access to commercial energy, to enter the market. We must, moreover, do everything in our power to close the gap between opulence and penury. We must create conditions that permit mankind to lead a decent life – there must be education, public health, work and homes for all the 6 billion inhabitants of Earth who, by the year 2020 will have risen to 8 billion and will number approximately 10 billion in 2050. There are no magical solutions. One of the objectives of the World Energy Council is to find paths that lead us to the incorporation in the world market of a neglected population of two billion which is forecast to reach 4 billion by 2020, should the status quo continue. In other words, instead of the current 30% of the world population without access to commercial energy, by the year 2020, half of the world's inhabitants would be deprived.

II. THE WEC TODAY: What is it?

The World Energy Council (WEC) is a unique multi-energy organization comprising approximately 100 countries worldwide. Its aims are to study, analyze and discuss matters of energy-related importance, so as to offer to both energy-opinion and decision-makers internationally its views, advice and recommendations.

Initiated in 1923, the World Energy Council started life as the international association of the electricity industry. It evolved to cover all forms of energy from oil and gas, through coal and uranium to hydro and new renewables such as solar power and wind. Today, it is the leading global non-governmental energy policy forum.

Throughout its history, the WEC has been non-governmental and non-commercial, and thus able to be objective and realistic in its thinking and actions.

III. MEMBERSHIP

Membership is vested in autonomous country Member Committees which themselves reflect the majority of local national energy and energy-related interests, often including government. Membership has now reached about 100 countries, representing some 92% of current world energy consumption. The WEC represents the spread and interests of its own membership from the industrialized through the "transitional" to the developing countries, but does not directly represent energy industries worldwide.

IV. OBJECTIVE

"To promote the sustainable supply and use of energy for the greatest benefit of all".

V. WEC IN U.S.

The United States Energy Association – USEA is the Member Committee of the World Energy Council. USEA is an association of 160 public and private energy-related organizations, corporations and government agencies. USEA coordinates participation of the United States in the WEC, nominates representatives to WEC activities, and organizes the U.S. delegation to the World Energy Congress, as well as other WEC forums.

USEA sponsors policy reports and conferences dealing with global and domestic energy issues and also sponsors trade and educational exchange visits with other countries. Membership in the U.S. Energy Association is open to all organizations having an interest in the energy sector of the United States.

As you can see, we, from the WEC, are not trying to reinvent the wheel, we just want to make it rounder.

After this break for a little marketing, let me turn to energy & economy related matters.

VI. CURRENT SITUATION

The current price of oil (14 US$/bbl) which reflects the general situation of world trade parallel to continuous records of peaks in the stock exchanges of developed countries proves my earlier comments.

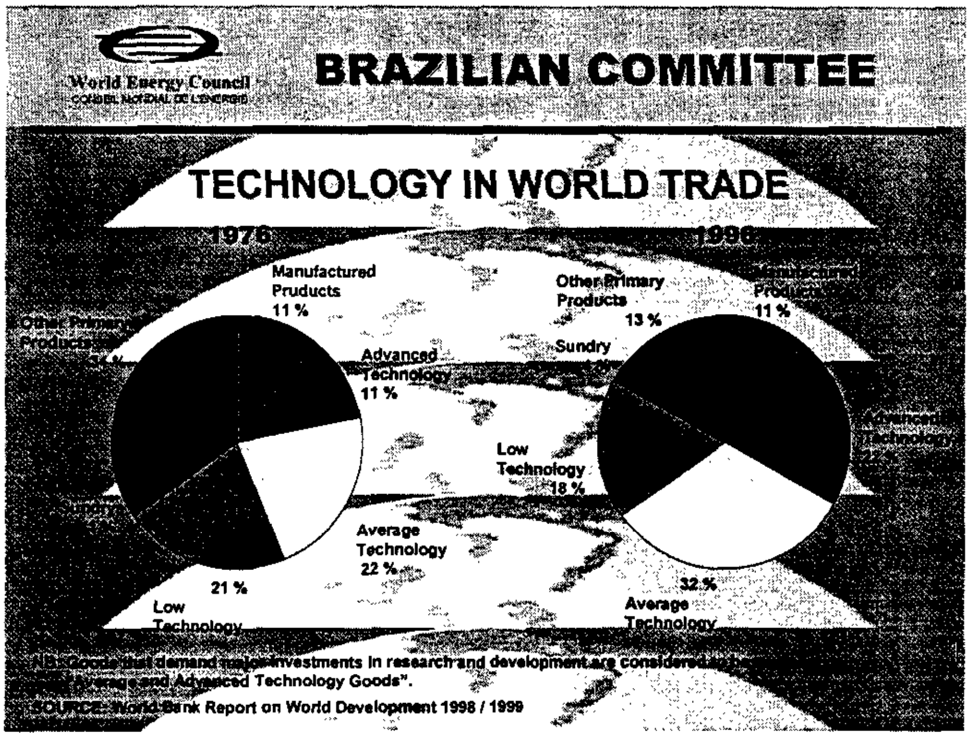


Figure 1 – Technology in World Trade

These graphs show you some interesting aspects of the evolution of product distribution in world trade, presented according to technology level (1976-1996).

In the drop of primary products and the substantial growth of countries with access to advanced and average technology you clearly see the decline in the participation of developing countries in world trade.

Having made these social-economic considerations, the questions arise: how will the energy market develop in this context? What will be the extent of participation by developing countries? What is expected of industrialized nations?

According to today's premises, economic growth is the main driving force of power demand. In general, a decline in performance is forecast for practically everywhere in the world. The only probable exceptions will be the economies in transition, which pick up their expansion after the crises of the nineties has been overcome.

As mentioned earlier, in this scenario, the current 6 billion people inhabiting the world are forecast to reach 8 billion by the year 2020, and 10 billion by 2050. It is estimated that 90% of this population explosion will occur in developing countries. Global energy demand of 9 Gtoe in 1990, is expected to increase about 7 Gtoe (to 16 Gtoe), by 2020; and developing countries will probably account for 6 Gtoe of this additional figure. These statistics could be lower if energy intensity in some developing countries 1990 level of declines rapidly, as was the case of India, Thailand and the Philippines. On the other hand, higher economic growth rate assumptions imply higher energy demand in traditional terms or higher environmentally related expenditures.

In many cases, therefore, different assumptions could give more or less the same results as the scenario used here. For example, the International Energy Agency (IEA) in its "business as usual" projection foresees for 2020 a total energy demand of 15 Gtoe, against the 16 Gtoe, considered here.

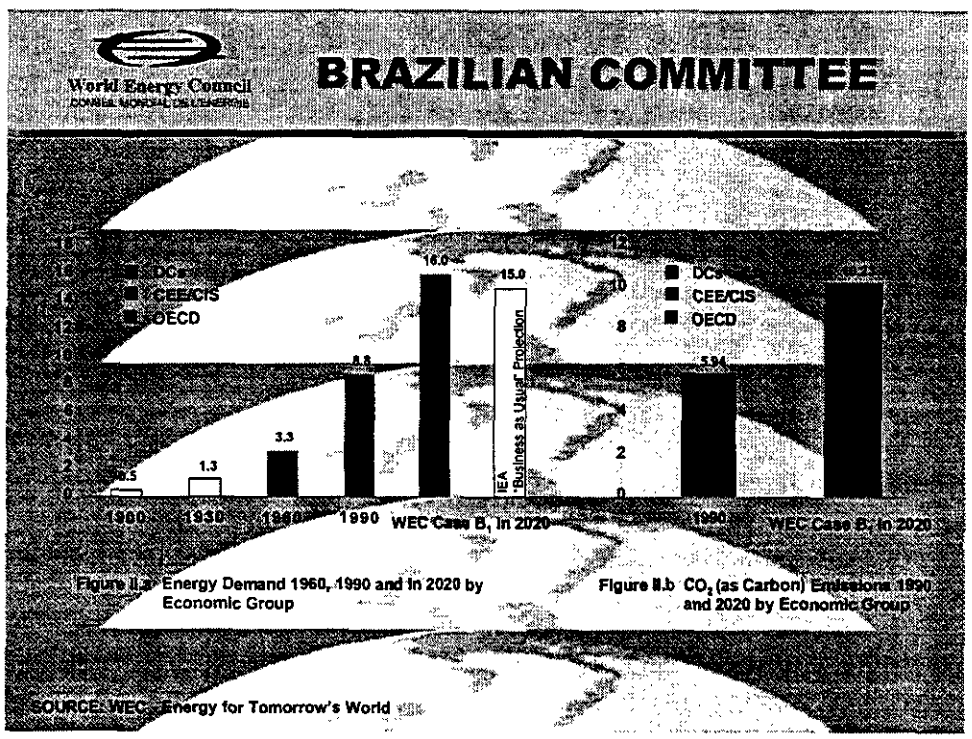


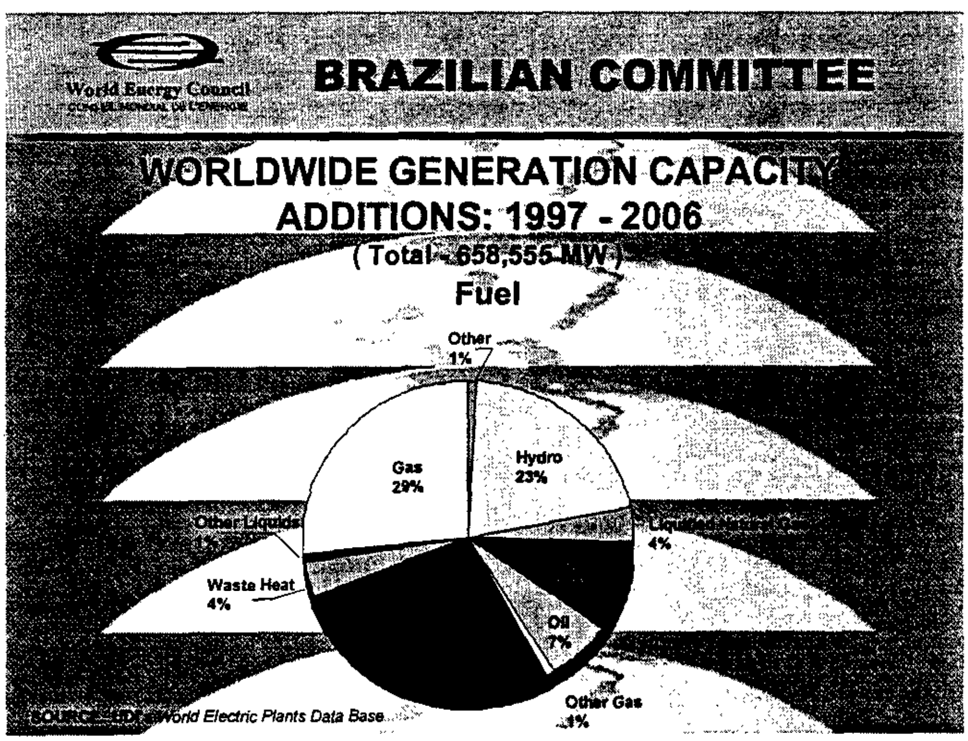
Figure II

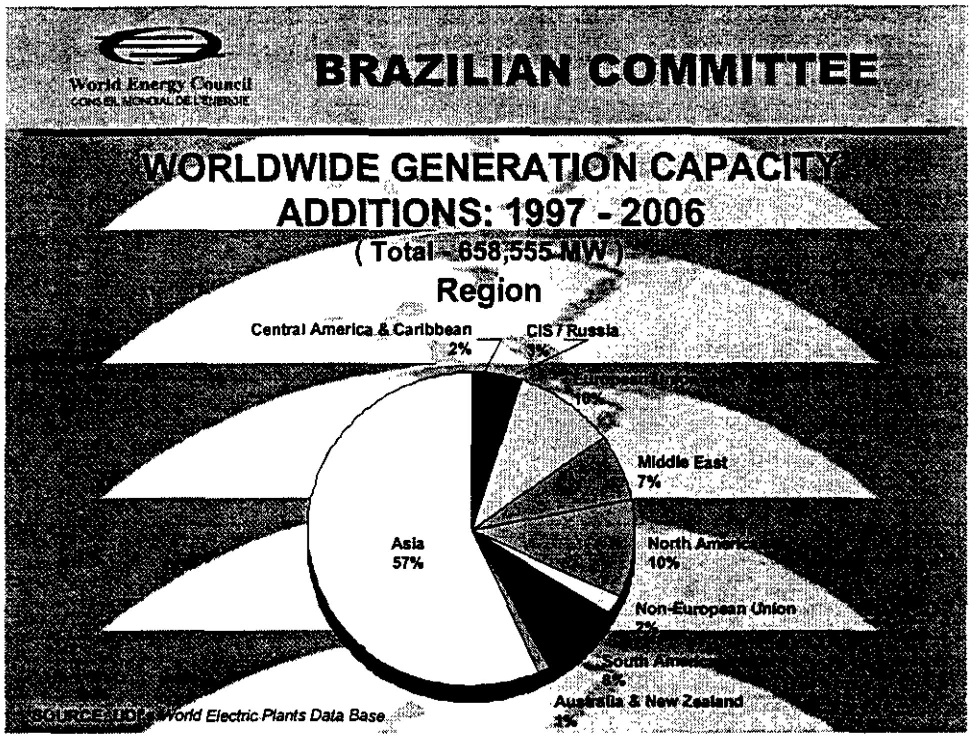
A recent survey of energy resources promoted by the World Energy Council shows that they are not the restraining factor here.

Thus, the following realities have to be faced:

- for many decades to come the world will have to rely upon fossil fuels for most of its energy supplies;
- the demand for coal, oil and natural gas will rise for the next few decades;
- coal is the only fossil fuel likely to be available in substantial quantities much beyond the middle of the next century;
- China and India have huge coal resources and huge energy needs. A number of other developing countries have very large coal reserves. The pressure to develop these is immense and seen locally to be of a very high priority;
- import dependency for fossil fuels will grow as existing producers run through their resources, with growing concern over supply availability and price.

The following two graphs, although referring to electric power, prove the predominance of fossil fuel expansion (70% of the total forecast for 2006, or a figure equivalent to 461,000 MW):





Regionally, this confirms the greater weight of Asia with a definite influence of China and India.

Having established the market, the question arises: where does the money come from? Will there be funds available for this major expansion?

The main objective of the primary energy demand mentioned here is to explore a plausible global framework for energy investments. In this scenario, the energy requirements of *developing countries, which were 2824 Mtoe in 1990, would grow to around 4.500 Gtoe in* 2000. Please note that this is 60% more than the 1990 consumption and that this figure is expected to reach 8.2 Gtoe in 2020, or 290% of the 1990 requirements.

Clearly, the magnitude of the implied energy investments is a huge challenge. To meet these energy demands of developing countries would require investments of about US$ 160 billion per year (at 1990 prices), over the next three decades, or the equivalent if approximately US$ 5 trillion cumulatively in the period. Any projection would lead to the conclusion that real investment flows in the energy sector will have to increase substantially compared with past trends.

CUMULATIVE INVESTMENT FOR DEVELOPING COUNTRIES
1990-2020 (billion of 1990 US$)

SECTORS	AMOUNT	SHARE %
Power	4015.2	81
Oil & Gas (Including refining costs)	835.9	17
Coal	121 6	2
Biomass & Other Renewables	.3	--
TOTAL	4973 0	100

The WEC has concluded that global financial resources are more than adequate to meet the vast need of the energy sector, but funds will be mobilized in sufficient quantities only if certain conditions are met.

A growing concern is that many of the economies-in-transition and developing countries may not be able to mobilize all the finance they require for energy investment, either because of inadequate public resources, or because they are unable or unwilling to make the essential changes needed to attract private sector investment.

With the increasing and competing demands for public finance, the rise of international aid budgets and the declining flow of international agency finance to state- to-state energy enterprises, the public sector in many developing countries will not be able to finance all the investments related to the energy demand.

To attract private sector capital energy –particularly for electricity projects – will increasingly be in competition with projects in other infrastructure sectors and with other national and international investment opportunities. Depending on the risk involved, returns on capital invested in the energy sector will thus have to be as high, if not higher, than other possibilities. Unless the risk (or reward) ratio is competitive, energy projects are liable to suffer from low priority delays and fail to materialize. So, while some energy projects in developing countries already attract private finance, especially where hydrocarbons can be exported to world markets, it is estimated that more than 55% of the Memoranda of Understanding for Energy Projects signed in developing countries since 1990 have failed to secure financing, and the energy projects involved have not succeeded.

In less developed countries, where the notion of government ownership and national patrimony exists in conjunction with state owned, managed and subsidized energy monopolies, it is unlikely that adequate international finance will be obtained. Many such countries also have external debt levels equal to one or more years of their total GDP. These countries frequently lack the legal and financial institutional frameworks that would be required to harness domestic savings. Most of the nearly 2 billion people who have no access to commercial energy who I mentioned earlier, live in these less developed countries spread out over Asia, Africa and part of Latin America.

That is the sad truth. We effected consultations, diagnosed the diseases, and have pinpointed some treatments that, if not leading to a complete cure, will at least relieve the major part of the distress. We ask ourselves, however: if the rich nations were unable or unwilling to earmark even less than 1% of their Gross Domestic Product for the development of the less privileged, how can we expect the joint undertaking referred to as "Sustainable Development" to materialize?

In closing, let me present to you some principles for successfully facing the distress of extreme poverty from UNESCO, as well as from WEC-UNFAO through the study on the challenge of Rural Energy Poverty in Developing Countries.

Jointly, the following are necessary:

- Development of endogenous capacities. Give every country, every nation, every individual the capacity to decide for himself, to choose for himself, to exploit for himself the natural resources that surround him. This requirement has a name: COOPERATION. It is something very different from the technical assistance or just simple assistance provided so far;

- Promoting a better quality of life in the rural environment. If we are able in peacetime to make use of all our resources, including those of the armed forces, the quality of life will reach a level at which emigration – first and foremost to the large belts of poverty that surround metropolises, and secondly to foreign countries – will cease or, at least, diminish significantly;

- Citizenship, participation, above all at municipal level. This is where democracy is consolidated, where all citizens must put the guidelines furnished by the government into practice. It is also here that UNESCO forecast great progress in job opportunities, in new ways of living an active life, especially for jobs related to the environment.

- Informal, permanent education, evidently important to education, but also to information, to the global requirement indispensable in today/s world which is COMMUNICATION. Let no-one say he missed the boat. Everyone should, during his lifetime, get on the bandwagon of education, the bandwagon of dignity, the bandwagon of readiness for democracy. This concept is one of the basic principles of the peace culture.

- There is tremendous scope for the building of productive partnerships, both among developing countries, and between the developing and more developed countries. These opportunities should be sought and nurtured it is here that a role exists for organizations such as the WEC. With its diverse and embracing membership, drawn from a wide range of countries, rich and poor, and all sub-sectors of the energy community, the WEC is well placed to take the lead in helping to build such partnerships.

- One avenue for such cooperation is the WEC's Regional Program. An appropriate objective would be the marrying of the expressed energy research and development needs of the Member Committees of the WEC in the developing world with the relevant research and development capabilities elsewhere. By following this model, the WEC could provide "brokerage" for rural energy research and development.

Finally, I must tell you that some of the thoughts submitted to you are not originally mine. They are, basically, the result of studies undertaken by the WEC and other international organizations such as the United Nations. They mirror my concerns perfectly, my concerns as a citizen of the world. I am anxious for developing countries to have access to clean energy producing technologies adapted to their respective situations and for a time when it will be possible to equate company profits with efficacious government action for the well-being of all peoples.

FUEL FOR THOUGHT: WORLD BANK GROUP'S PERSPECTIVE AND CLEAN COAL PROGRAM

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ABSTRACT

Developing countries will not be able to lift themselves out of poverty without increased use of modern forms of energy. Even with improved efficiency and increasing use of new and renewable source of energy, demand will grow and that will be met by fossil fuels, in many cases by coal. However, worsening of air pollution caused by coal use, already causing million of respiratory illness each year, can be expected. Greenhouse gas emissions from the developing world, though still lagging far behind those from industrialized countries, will grow. Combined, these circumstances create a powerful mandate for cleaner fossil use and clean coal technologies.

This paper presents World Bank's perspective on the environmental strategies for the next century in energy sector: making markets work and integrating environmental costs. The paper also presents Bank's clean coal programs and some of the key findings of the technology assessment and environmental options case study in China. We have completed two provincial case studies: Shanghai and Henan and are currently working on the third province: Hunan as well as assessing clean coal technology by using Technical Assessment Guide (TAG).

I. WORLD BANK'S ENERGY AND ENVIRONMENTAL STRATEGIES: FUEL FOR THOUGHT

(Slide 1: Fuel for thought)

In 1992, the World Bank completed three important reviews of its experience with the energy sector in developing countries. The first review looked at the financial and economic performance of the electric power sector, the second addressed energy efficiency, and the analyzed the relationship between economic development and the environment. The third looked at rural energy access.

These reviews show that governments in developing countries intervene in energy markets with results, which harm both economic growth and the environment. Reducing these policy distortions represents a "win-win" approach. The World Development Report pointed in particular to the need to eliminate subsidies for the use of fossil fuels and to make heavily polluting state-owned firms more competitive.

The paper on power pointed to big inefficiencies in the electricity sector. Older power plants in developing countries, for example, consumed 20 to 50% more fuel for each unit of electricity produced than plants in OECD countries.

(1) In general, the WBG will only invest in a country's energy sector if that country shows commitment to improving efficiency by restructuring the sector or reforming its policies. Support the momentum towards further sectoral restructuring or policy reform.

(2) WBG will support competition, private-sector investment, and sound regulation of the sector.

(3) WBG will promote energy efficiency both on the supply side and the demand side, and integrate energy pricing with environmental policies.

(4) WBG will help to improve access to modern forms of energy for the two billion people in rural areas who must rely on traditional forms of energy such as fuelwood and agricultural waste.

The World Bank Group is not only recommitting itself and working harder putting into practice its existing policies; but it is now making additional efforts in the field of energy and the environment. Specifically:

(1) In order to achieve the maximum possible leverage over the development of the energy sector, the WBG will do more work upstream to guide lending for projects within the priorities laid out in the country assistant strategy (CAS). It will work with governments to undertake "Energy-Environment Reviews" to set priorities for action across the whole energy chain. It will help governments refine, implement and enforce national air pollution standards, ensuring they are cost-effective and tailored to national conditions.

(2) The WBG will bring environmentally friendly technologies and practice into the mainstream of its operations. It will undertake high-visibility projects and programs involving renewable energy and energy efficiency. It will step up direct involvement in environmentally and socially sound clean coal technology, natural gas development, and hydropower.

(3) The WBG will help to improve standards of analysis for environmental problems, and its monitoring of projects aimed at solving them. More work needs to be done, for example, to estimate accurately the costs of different types of pollution in different regions.

(4) The WBG will support worldwide efforts to avert the threat of climate change. It will encourage the use of new technologies that reduce greenhouse gas emissions. It will play a role in the establishment of a global market in carbon emissions offsets and credits, which should help cut the costs of averting climate change.

(Slide 2: Making Markets Work)

Pricing and Restructuring
In the power sector, the Bank has given high priority to reforming and restructuring, and generally, projects will not be considered by Bank management without attention to these issues.

One problem frequently cited by Bank Group staff is the slow progress in the establishment of sound regulatory frameworks for the power sector. Also large problems remain in South Asia, the Middle East, and Africa, where few countries have energy prices which are close to long run marginal costs of production; and in most countries prices remain (to some extent) distorted by cross-subsidization.

Energy Efficiency
Energy efficiency is also an important issue, but the largest issue is not necessarily power generation efficiency. Power industries in developing countries often lose more than 20% of their electricity due to theft or T&D inefficiency. One way to stop this is to encourage either private sector participation (as in Côte d'Ivoire) or complete privatization (as in Argentina and Chile). Losses in Argentina and Chile are now at an acceptable level of 10–12%.

(Slide 3: Integrating Environment: Policies)

Energy-Environment Reviews: A New Tool
The WBG will undertake in the energy sector a program of Energy-Environment Reviews (EERs) that will cover the whole energy chain and the whole range of its environmental impacts. EERs will help to map out what the Bank Group will do in the sector regarding energy supply and demand, as well as pollution avoidance and control in areas such as efficiency, conservation, rehabilitation, and decommissioning.

Establish and apply environmental and social standards
The Bank has a comparative advantage in being able to carry out a dialogue across many sectors and across many different ministries within a country. It will make use of this capability to encourage the development and implementation of the most cost-effective national air pollution standards. Governments will be encouraged to use the Bank's *Pollution Prevention and Abatement Handbook* to review the existing conditions against international standards and then to prepare a set of pollution guidelines adapted to local circumstances. Assistance will be provided through the EERs and through follow-up technical assistance work to raise public awareness of costs and benefits of environmental clean-up, to help governments put in place pollution monitoring equipment, and to build institutions able to monitor and enforce the standards.

II. CLEAN COAL PROGRAM

The World Bank launched a Clean Coal Initiative in 1996 at the first Roundtable. The Initiative is a whole coal chain approach starting from win-win option such as coal and power sector reform. As the first step of the Initiative, we have started Clean Coal Program in China that includes whole sector of coal chain: coal mining, transportation and utilization. In the program two parallel activities have been started: one starts from sector reform and another starts with Clean Coal Technology Assessment and Environmental Control Options Least Cost Case Study.

We have started latter study since early this year, by forming international and local consultant team. The study team consists of Electric Power Development Co. (EPDC, Japan), Tokyo Electric Power Company (TEPCo, Japan), Electric Power Research Institute (EPRI, USA), Beijing Economic Research Institute (BERI, China), Thermal Power Research Institute of Xian (TPRI, China), Nanjing Environmental Protection Design Institute (NEPRI, China) and Clean Coal Research Institute (CCRI, China). Our major counterparts in China are State Power Corporation (former Ministry of Electric Power), Coal Bureau (former Ministry of Coal), State Development and Planning Commission (SDPC) and State Economic and Trade Commission (SETC). The study has three tasks:

(1)Technology Assessment: We are looking at performance, cost, cost-effectiveness, technology readiness, adaptability to China of all options in power and non-power sectors.

2) Case study: This is the third case study in a row. We have completed Shanghai and Henan studies. We are now looking into Hunan province. We are adding dispersion and environmental impact cost analysis by contracting Tsinghua University.

3) CCT site tours and workshop: We have managed to arrange Chinese technical experts to visit CCT site in Japan and Europe, and we are asking our friends in DOE to support such tour in the US.

The study team made two missions to China in March and April/May, visiting power Shanghai, Shangdon, Shanxi, Hunan and Sichuan provinces and three boiler manufacturers of Harbin, Dongfang and Shanghai.

The team is in the process of analyzing data and running the model for the case study. We are expecting to have a final draft report in autumn, and are planning to have a workshop to disseminate the findings and methodologies.

(slide 4: Henan, particulate emissions from various sectors)

Main sources of particulate emissions are residential and non-power industry sectors, which contribute approximately 80% of the total emissions in Henan, with the remaining of 18% contributed by the power sector. Within the power sector, 73% of the particulate emissions (13% of the total) are coming from small power plants (less than 125 MW), and the larger unit size plants (larger than 125 MW) emit only 27% (5% of the total).

(slide 4: Henan, cost effectiveness of control options in non-power sector)

In non-power sector, options such as briquette use rather than raw coal use in rural household and industrial boiler, or conversion to gas from coal at urban household can remove large amount of pollutant at low cost:

- briquettes for rural household can remove 19 million ton of SO2 eq. at a cost of $21/ton of SO2 eq.
- *coal washing for household can remove 2.4 million $39/ton of SO2 eq.*
- briquettes for industry can remove 14 million ton of SO2 eq. at a cost of $115/ton of SO2 eq.
- gas for urban household can remove 8.4 million ton of SO2 eq. at a cost of $118/ton of SO2 eq.
- coal washing for industry can remove 1.7 million ton of SO2 eq. at a cost of $130/ton of SO2 eq.

(slide 5: Henan, cost effectiveness of control options in power sector)

In power sector, amount of pollution reduced is smaller and cost is higher than non-power sector options, however implementation of the options seem to be easier than the non-power options because of the numbers of the emission source involved. Among the power sector options, ESP rehabilitation of small boilers and accelerating retirement of small units are cost effective and having large impact in reducing pollutant emissions, follow up Flue Gas Desulfurization (FGD) options:

- combustion tuning is the lowest cost option at $14/ton of SO2 equivalent removal and can remove 570,000 ton of SO2 equivalent during the period of 1997 -2020
- ESP rehabilitation of existing small units can remove 5 million ton of SO2 eq. at a cost of $41/ton of SO2 eq.
- low NOx burner can remove 350,000 ton of SO2 eq. at a cost of $87/ton of SO2 eq.
- accelerating retirement of small units can remove 3.5 million ton of SO2 eq. at a cost of $220/ton of SO2 eq.
- simplified FGD can remove 5.1 million ton of SO2 eq. at a cost of $280/ton of SO2 eq.
- when the World Bank's new guideline is applied to all new units of ESP (50 mg/Nm3), it can remove 600,000 ton of SO2 eq. will be removed at a cost of $450/ton of SO2 eq.
- wet FGD can remove 5.6 million ton of SO2 eq. at a cost of $470/ton of SO2 eq.
- coal washing can remove 2 million ton of SO2 at a cost of $480/ton of SO2 eq.
- SCR can remove 450,000 ton of SO2 eq. at a cost of $1,050/ton of SO2 eq.

- AFBC, PFBC and IGCC can remove around 1.5 million of SO2 eq. at costs of \$1,600/ton, \$2,100/ton and \$2,300/ton of SO2 eq.

Most of the small units (less than 200 MW) are not equipped with Electrostatic Precipitator (ESP) to control particulate emissions. Ventury scrubber, water film or other typed of more primitive and less efficient particulate control devices are used. Retrofitting ESP to such small units will improve control efficiency significantly at low cost. Very Small units (typically 6 or 25 MW) have very low efficiency and high emissions rate of pollutants. Therefore, these plants should be retired at earliest possible date and replaced by the large and more efficient power generating capacity.

There are several demonstration project of Flue Gas Desulfurization (FGD), but the deployment of the FGD to commercial units has not been progressed. The regulation is not clear and distinct enough for the utility to start installation of FGD. Domestic and foreign manufacturers are also wait and see the policy to be defined clearly for the potential big market.

Circulating Fluidized Bed Combustion (CFB) boilers, on the other hand, are becoming a real business. Domestic boiler manufacturers are providing CFB boiler less than 100 MW. Utilities have been accumulating experiences in operating and maintaining CFB. There is a 300 MW CFB project on going with technology transfer from Europe and US.

Supercritical technology has a great potential to increase plant efficiency and reduce emissions of the large power plant (larger than 500 MW). There are more than ten units of supercritical plant operating in China. They have been demonstrating high availability of the units when the staff has enough training. Domestic manufacturers have been acquiring manufacturing capability of supercritical technology, but they have no experience. Technology transfer is the critical issue of the quick deployment of the technology in Chinese market and significantly reduce emissions. For more advanced CCTs such as IGCC and PFBC, current high cost and associated technical and commercial risks need to be overcome. But Chinese government is interested in demonstrating these technologies and localizing as much as possible to reduce cost. WBG together with GEF new partnership, keep dialogue how to support technology transfer and development of the advanced technologies.

(slide 6: Methodology development)

We have been developing methodology of environmental control options through the case studies. In Shanghai study, we have found the large capacity and cost effectiveness of non-power options and included in the study. Externality sensitivity study was carried out in Shanghai study. In the Henan case study (second study), optimization of cost effective combination of each options have been introduced, and non-power sector and externality analysis were carried out more extensively. In the third study (Hunan province) dispersion model has been introduced and externality analysis is being carried out in more comprehensive manner.

(slide 7: related WB web pages)

Energy and Environment Strategy paper "Fuel for thought" can been downloaded at the WBG's web site: http://www-esd.worldbank.org/cc/wbstart.html

"Pollution Abatement and Prevention handbook" has been revised and published in August 1998. Sections of the handbook can be accessed and downloaded at:
http://www-esd.worldbank.org/pph

Clean Coal Technology Assessment in China study has been put into the EM Power Info web page: http://www.worldbank.org/html/fpd/em/emhome.htm and it will be updated regularly. The related papers produced under technology partnership, such as supercritical technology, modular construction, gas turbine technology, Brazil biomass gasification combined cycle risk analysis have also been put in the web site.

Public-Private Initiatives

WBG will continue to expand its cooperation in the international energy industry through partnerships with groups like the Electric Power Research Institute (EPRI), the grouping of power companies from industrialized countries (the 'E7'), and international oil companies, manufacturing companies. As a pilot phase, we have worked together with Siemens on the Knowledge Management and Technology Partnership, published three papers on supercritical technology, modular construction and gas turbine technology in the above Bank's web site and Bank's publication "Energy Issue. We are open to any other partners, and have started discussion with others including ABB, Alstom, Mitsubishi, and Hitachi. We would like to use this opportunity to further develop partnership. Let us know if you are interested in the technology partnership with the World Bank.

Fuel for thought: World Bank Group's perspective and Clean Coal Program

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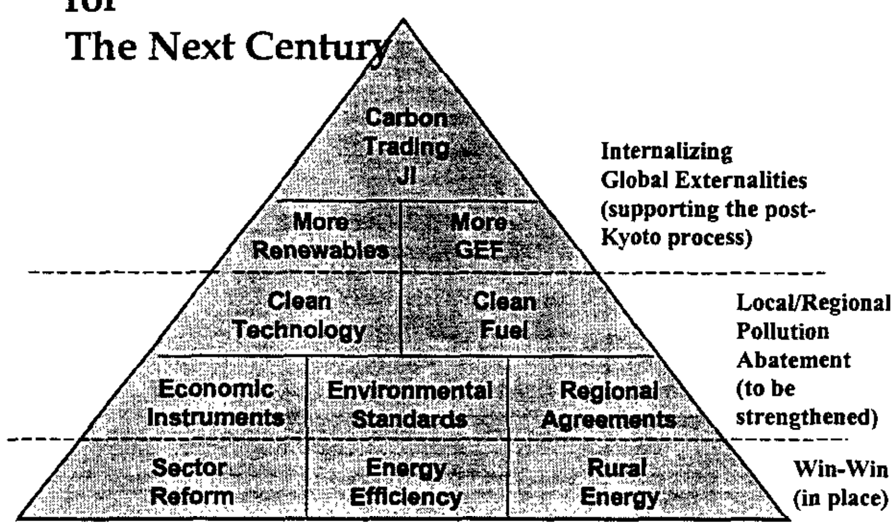
7th Clean Coal Technology Conference
Knoxville, Tennessee, June 21-24, 1999

Fuel For Thought: Environmental Strategy for The Next Century

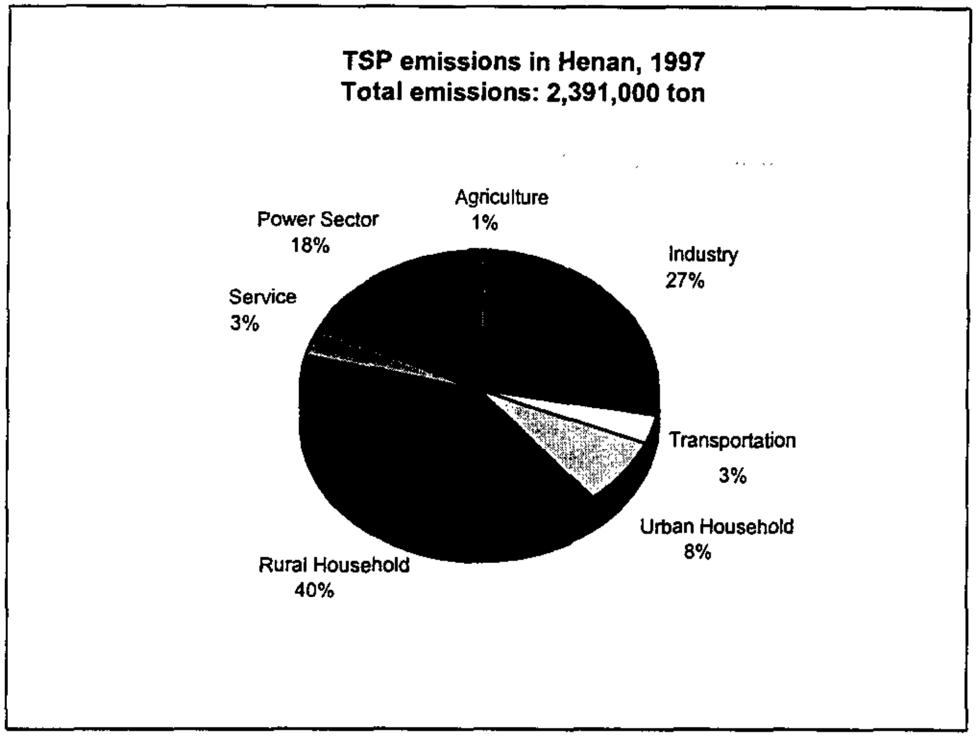


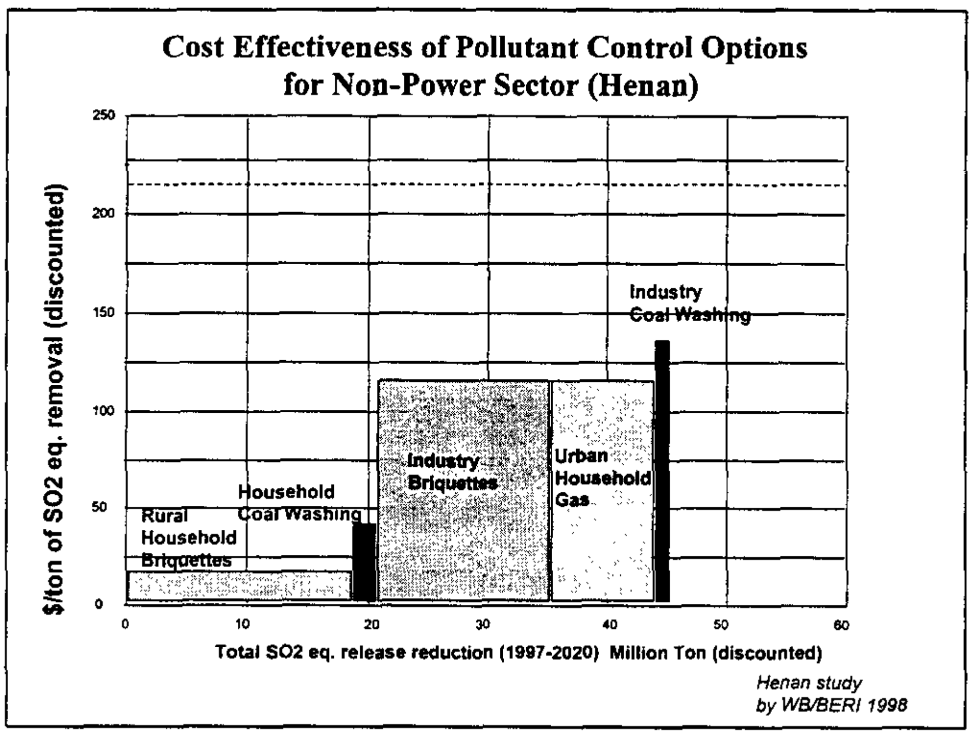
Making Markets Work

- Pricing
- Reform
- Energy efficiency
- Fuel switching
- Power and gas trade

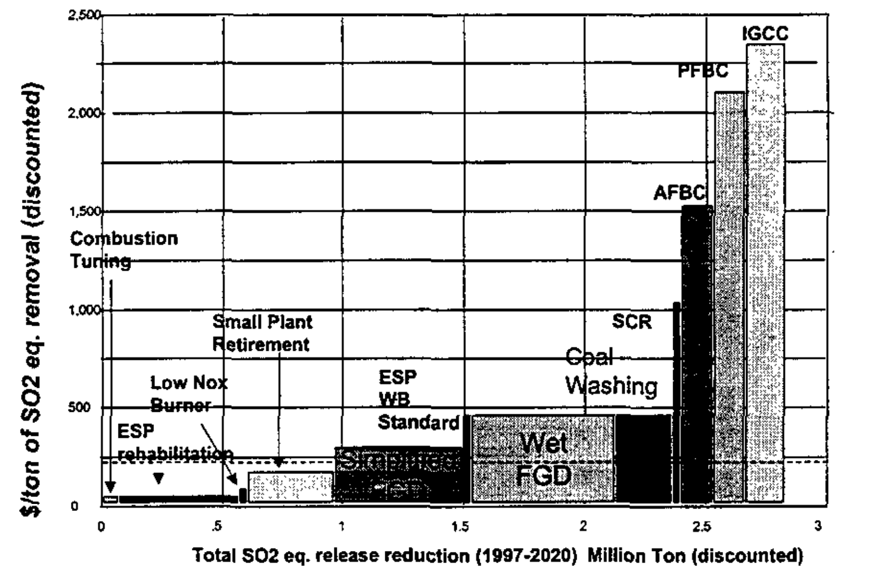
II. Integrating Environment: Policies

- Fund and aggressively promote "upstream" energy and environmental reviews.
- Mitigate emissions through standards and taxation, build enforcement capability.
- Targeted support for transitional environmental compliance costs.
- Include environmental costs in analysis.
- Create markets (local emissions, global carbon emissions).


TSP emissions in Henan, 1997
Total emissions: 2,391,000 ton
Agriculture 1%
Power Sector 18%
Industry 27%
Service 3%
Transportation 3%
Urban Household 8%
Rural Household 40%

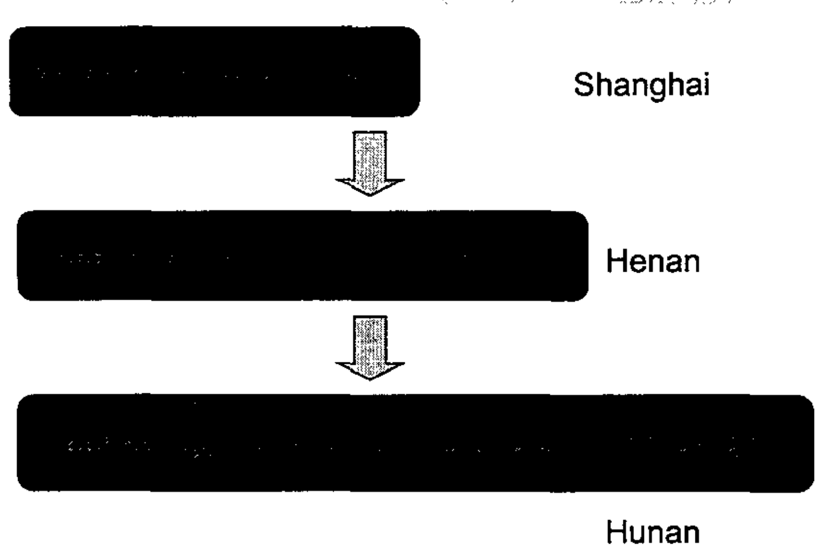

Cost Effectiveness of Pollutant Control Options for Non-Power Sector (Henan)
$/ton of SO2 eq. removal (discounted)
Industry Coal Washing
Industry Briquettes
Urban Household Gas
Household Coal Washing
Rural Household Briquettes
Total SO2 eq. release reduction (1997-2020) Million Ton (discounted)
Henan study by WB/BERI 1998

Cost Effectiveness of Pollutant Control Options for Power Sector (Henan)



Henan study by WB/BERI 1998

Least Cost Environmental Compliance Strategy - Methodology Development



Related World Bank web site

- Environmental Management for Power Development (including CCT)
  www.worldbank.org/html/fpd/em

- Energy and Environment Strategy (Fuel for Thought)
  www-esd.worldbank.org/cc/wbstrat.html

- Pollution Prevention and Abatement Handbook (Environmental guideline)
  www-esd.worldbank.org/pph

FINANCING POWER PROJECTS IN THE DEBT MARKETS

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ABSTRACT

Power plants are financed through a combination of debt and equity. Debt can be provided from the financing markets either in the form of commercial bank loans or through the sale of bonds. Depending upon the risks and structural needs of the project, as well as upon the current bank and bond markets, sourcing one market may be preferable to sourcing the other. Lenders and investors often have many financing opportunities from which to choose. They first judge the riskiness of each investment and then choose the acceptable investment yielding the highest return. In making lending/investing decisions, banks and bond purchasers must judge the project's sponsors, technology, construction and operating plans, offtake arrangements and fuel supply arrangements. They must also consider political, regulatory and environmental risks. When considering investing in a project with new technologies, the lenders and investors will carry out additional due diligence and will most likely require strong completion guaranties and post-completion warranties. They often require the opinions of expert independent consultants when making a lend/no-lend decision and would certainly require assistance from such consultants in judging new technologies. A project employing a new technology may also require higher equity levels. Some project sponsors may find such higher required equity levels uneconomic and may consider, if possible, on-balance sheet financing until the technology becomes proven.

I. INTRODUCTION

I'm here today to speak about debt financing of power projects. First, I'd like to tell you about the company I work for, Moody's Investors Service, and the role Moody's plays in the debt financing markets. Next I'll describe sources of financing for projects. Then I'll discuss how lenders[1] decide which projects to finance, how they analyze project risk and which financial covenants they require. Lastly, I'll make a few comments on coal-fired plants. The main message, however, I would like to leave with you is that *projects must be well structured and profitable to secure debt financing.*

[1] Note that, throughout this paper, unless the context indicates otherwise, the word "lender" refers both to a bond purchaser or to a bank or institutional direct lender.

II. MOODY'S INVESTORS SERVICE

First let me tell you about Moody's Investors Service. Moody's was found by John Moody in 1900 and issued the first bond ratings in 1909. By the 1920's, Moody's was rating most of the corporate bonds in the United States. Currently, Moody's rates many debt obligations including bonds, commercial paper, certificates of deposit, asset-backed securities, mutual funds and counterparty risk. Moody's reach is worldwide and provides ratings for all the major sovereign, corporate, municipal and structured finance issuers in over 50 countries and serves 30,000 investor clients in over 60 countries.

I work in Moody's Power Group. Moody's Power Group rates the debt obligations of domestic and international entities in the businesses of power generation, transmission and distribution. Examples of entities we rate include Northern States Power Company, Endesa (Chile), the UK REC's, AES, Sithe's Independence Station, Homer City and Paiton Energy. Susan Abbott heads the Power Group, which comprises 16 people in New York with others in London, Hong Kong and Sydney.

III. MOODY'S RATINGS

A Moody's rating is Moody's opinion of the future ability and legal obligation of an issuer to make timely payments of principal and interest on a fixed income security. Moody's highest rating—that is, the rating for bonds which Moody's believes have the lowest default risk--is Aaa. As default risk increases, Moody's ratings drop from Aaa to Aa, A, Baa, Ba, B, Caa, Ca and C. All categories except Aaa, Ca and C have sub-categories 1, 2 and 3. Bonds rated from Aaa down to Baa3 are referred to as investment grade. Lower-rated bonds are referred to as sub-investment grade. Bonds rated Caa, Ca or C are likely near or in default. Because of the great number of institutions willing to invest in investment grade bonds versus sub-investment grade bonds, investment grade bonds carry significantly lower interest rates than some investment grade bonds. Moody's average U.S. electric utility senior secured bond rating is A3 and average U.S. project financed power plant bond rating is Baa3.

IV. POWER PROJECT FINANCING TECHNIQUES, SOURCES

Power projects are financed primarily by three methods. The first method is corporate or balance sheet financing. This method is employed by companies willing to finance the entire cost of a project on the company's corporate balance sheet. The second method is called either project finance or non-recourse finance. In this method the project sponsor raises funds from lenders who can only look to the success of the project to repay the loans, i.e. the lenders do not have recourse to the sponsors of the project. If the project ends up failing, the lenders can only foreclose on the project whose value has obviously been compromised. Although corporate financing is often cheaper than project financing, corporate financing of good-sized projects can use up scarce debt capacity on a corporation's balance sheet. The third technique is a hybrid of the first two techniques. Many project financings carry corporate guarantees for specific project risks—for instance, construction risk.

Projects obtain financing in the form of debt, mezzanine financing and equity. Debt can be provided by banks, institutional lenders, the sale of bonds or from certain other sources. Project bank debt is provided by a small group of sophisticated lenders from the U.S., Canada, Europe, Japan and Australia. Institutional debt is provided by a smaller group of primarily U.S.-based sophisticated long-term lenders. Project bonds are purchased by a much larger pool of investors, primarily by insurance companies, pension funds and investment funds. Mezzanine financing can be provided in the form of subordinated debt, preferred stock or other similar instruments. Mezzanine financing providers are generally financial institutions looking for higher returns and willing to take greater risk and include certain insurance companies, trust companies and industrial companies. Equity is most often provided by the project sponsor, but can also be provided by financial investors seeking a high return either in the form of cash dividends or tax benefits.

V. BANK DEBT VERSUS BONDS

Projects must consider several factors when choosing between borrowing bank debt or selling bonds. At first, one might think that the interest rate would determine the choice. Project bonds are sold at fixed rates calculated as spreads over comparable average life treasuries and bank loans are structured with floating rates calculated as spreads over the floating LIBOR rate. However, banks also very often require borrowers to fix floating interest rates through interest rate swaps or other hedging instruments. Given that hedging instruments are tied to the treasury market, the resulting fixed rates on bank loan financings are often not dissimilar to the fixed rates on bond financings.

A more relevant consideration is term. Although the longest term banks are willing to lend has increased and decreased over the years, generally one can expect to obtain bank loans no longer than construction plus 15 years, even for the strongest projects. The bond markets, on the other hand, have recently financed power plants with bond terms over 25 years. Both banks and bondholders, however, will require full or substantial amortization during the term and will lend no longer than they believe the facility can operate economically.

To the extent a project plans to finance during construction, the project may prefer bank loans over bonds. Bank loan commitments can be drawn down as needed during the construction period. Bonds must be sold up front and proceeds not immediately used must be invested, often at rates less than the interest rate being paid on the bonds. The project will then lose money on the interest spread until the funds are used. If this negative spread is greater that the bank loan commitment fee, the sponsor may choose the bank loan.

Transactions costs may also factor into the sponsor's decision. Whether financing through the bank or the bond markets, most sponsors find up-front financing, legal and consulting fees expensive. On smaller transactions, however, sponsors will most likely decide that the up-front fees incurred obtaining a direct project loan will be cheaper than those incurred selling bonds. On larger financings, the opposite may be true.

The sponsor may also consider the perceived long-term intrusiveness and flexibility of the bank lenders versus the bondholders. Although bank lenders' loan documents give the bank great control, banks can also react reasonably quickly to changing project conditions or sponsor requests. Bond indentures are generally considered to be less intrusive but less malleable. Sponsors will likely find bank lenders easier to mobilize than the more distanced bondholders.

One additional difference between the bank and bond markets is the linkage between the credit and lending decisions. In the bank markets, the same institution makes the credit decision and the lending decision. A bank's own credit department determines whether a loan officer can make the loan. The bond markets have slightly de-linked the two functions. Bond investors recognize the credit judgments of Moody's Investors Service and a few additional rating agencies. Ultimately, investors make their own decisions when buying bonds. Investors, however, recognize the rating agencies' significantly greater access to project information, and the rating agencies' bond ratings and opinions factor importantly in the bond purchase decision.

VI. LENDERS' CHOICES

As discussed above, a project sponsor must approach a relatively small, very sophisticated universe of potential lenders when seeking financing. The project sponsor must recognize that each of these lenders is likely considering other projects also seeking debt financing. How do lenders choose between competing project lending opportunities? Lenders choose after considering several factors. Initially, lenders will analyze the projects' risks. Given equal overall risk, lenders will choose to finance projects offering the highest return. Lenders may also weigh portfolio considerations. For instance, lenders may already have lent too much to projects utilizing certain fuels or technologies or to projects located in particular countries. Certain lenders may be a full up on long term commitments and not want to lend long enough to finance fully the project. Lenders may also be temporarily capital constrained and therefore not aggressively making new loans. In addition, for various reasons, mostly historical or philosophical, banks may not make loans to certain businesses. For instance a bank may not finance a certain technology if it has written off a loan for a project using that or a similar technology. Likewise, some banks prefer avoiding certain industries such as armaments or gaming. Lastly, a bank may consider relationship history or potential.

VII. LENDER RISK ASSESSMENT

Lenders assessing project risk will consider the following factors: sponsors, technology, construction, operations, fuel supply and power offtake. Lenders will also examine the environment in which the project will operate. The lender will consider political issues, governmental and regulatory issues, environmental issues and possible effects of third parties. Of course, lenders will confirm the project has obtained its required permits and appropriate real estate rights.

Sponsors

Lenders will prefer experienced, well-heeled sponsors with strategic business reasons for entering into the project. To the extent the sponsor lacks experience with a particular technology or market, joint venturing with an appropriate partner or hiring the appropriate expertise may suffice. To the extent the sponsor lacks necessary deep pockets, third party guarantees or bank letters of credit may be required to back the sponsor's financial obligations. No third party guarantee or bank letter of credit, however, can make up for a sponsor in precarious financial condition. Although non-recourse financing looks to the project and not to the sponsor, lenders avoid lending into situations where the sponsor may have its own, non-project, difficulties.

Technology

Lenders prefer well-proven technologies. Even with well-proven technologies, however, lenders will require independent expert consultants to examine the technology on the lenders' behalf. The lenders will also require appropriate guarantees and warranties. Lenders' process and requirements will become more rigorous when the technology is somewhat unproved. The independent consultants' due diligence will be more intense and guarantees and warranties stronger. The lenders may also require the sponsors to provide greater amounts of equity, in effect requiring the sponsors to "put their money where their mouth is." Given that, with new technologies, lenders may require strong support measures, sponsors may choose instead to construct projects using new technologies on their own corporate balance sheets and then project finance once the technology is proven.

Construction

With regard to construction--with rare exceptions--lenders require fixed price turnkey construction contracts. Lenders strongly prefer that the construction contract be entered into with a financially strong contractor with long experience constructing similar facilities. Lenders will require construction contracts with acceptable scopes of work, construction and completion schedules, performance tests, liquidated and buydown damages and warranties. Lenders will also require appropriate collateral to support the contractor's liability, retainage, liquidated damages and punch list obligations. Financially very strong contractors, of course, can provide their own corporate credit as acceptable collateral.

Operations

With regard to operations, lenders require that the project operator be contracted prior to construction. Often a subsidiary of the project sponsor, the operator may also be a third party contractor. The operations contract should provide operating standards which, if not met, can allow the project to dismiss the operator. The lenders satisfy themselves that the operator has appropriate experience and can attract the appropriate key personnel required successfully to successfully the project.

Fuel Cost

Given that future power projects will primarily sell power at prevailing market prices, i.e., merchant plants—lenders' attitudes toward fuel supply risk have somewhat softened. Lenders now focus on fuel availability versus fuel cost. In this respect, lenders have begun viewing gas similarly to coal. Lenders assume gas plants cannot long term beat market gas rates and cannot risk long-term gas supply contracts whose prices may stray above market prices. Lenders instead now accept projects' buying gas at market prices. Fuel cost is the overwhelmingly largest operating cost of gas- and coal-fired plants. In past years, when projects sold power pursuant to contracts at scheduled prices, lenders focused on the project's ability to obtain fuel at prices tracking the scheduled power sales prices to ensure a positive operating margin. Addressing fuel risk in a merchant power environment, lenders will now instead determine which fuel is likely to set the marginal power price and make sure the project's operating costs—again, overwhelmingly fuel cost--will ensure a positive operating margin against that market power price *assuming all projects' fuel prices move with market prices.* In most markets, lenders assume natural gas fired power plants will long term set energy rates and that energy rates will therefore largely move with market gas rates. If a project is gas-fired and the project's heat rate is better than or equal to that of gas-fired projects setting marginal power rates, lenders feel fairly comfortable that an operating spread has been locked in. To the extent a project burns another fuel or utilizes technology different from gas-fired plants setting marginal rates, lenders will determine whether that different fuel or technology results in cheaper and/or more efficient power production. If so, lenders can also become comfortable with that fuel risk.

Fuel Transportation

With regard to gas-fired projects, the lender will assure himself that appropriate pipeline capacity exists. With regard to coal-fired plants, the lender will assure himself that appropriate reserves exist and that the transportation arrangements are adequate. The lender will also consider the type of coal being burned in the context of changing environmental regulations.

Power Offtake

As stated before, lenders recognize that independent power projects--and indeed many utility power plants--are moving from arrangements where adequate revenues are assured to unregulated competitive markets where revenues depend upon changing electrical energy and capacity markets. For the foreseeable future, stand-alone, pure merchant power plants must exhibit exceptional financial robustness in order to attract bank lenders or achieve investment-grade ratings. Recognizing this fact, project sponsors have devised several techniques for mitigating merchant risk, such as interim power contracts, tolling arrangements, power contracts for a portion of the project's output or by getting fuel suppliers to subordinate fuel costs to debt service. Insurance companies have also very recently developed "spark spread" insurance to mitigate merchant risk. Given that this "spark spread" insurance product is very new, it remains to be seen whether project sponsors, lenders or rating agencies will accept it.

Assessing merchant power risk, lenders rely heavily on independent power rate consultants. Power rate consultants provide projections of energy prices and capacity prices for the project's region. Power rate consultants base their predictions on assumptions for region definition, demand growth, generation supply growth, transmission, equipment advances, fuel types and prices, projected variable and fixed costs for future generation additions and reserve margin. Obviously, predicting energy and capacity rates 15 to 25 years out based on these many assumptions results in some uncertainty, and lenders and a rating agencies subject these rate projections to stress tests and haircuts.

Exogenous Risks

As I said before, projects also face exogenous risks: political risks, governmental and regulatory risks, environmental risks and third party risks. The lender must assess these risks when determining whether or not to lend. These risks are somewhat self evident, so I'll just give examples of each. A good example of political risk would be the recent events in Pakistan, where the change in government has placed several existing and proposed power plants under great uncertainty. Good examples of governmental and regulatory risk would be the recent United Kingdom Windfall Profits Tax and certain Federal Energy Regulatory Commission actions. Environmental Protection Agency policies and possible ramifications of the Kyoto Accord exemplify environmental risk. Lastly, with regard to third party risk, a very good example would be Columbia Gas' unexpected bankruptcy several years ago which resulted in intense lender focus on projects with Columbia gas supply, transportation or ownership arrangements.

VIII. FINANCIAL RISK ANALYSIS

Assessing a project's financial risk, lenders will examine the project's projected debt service coverage ratios, the project's debt to equity ratio and the owner's return on investment. Lenders will require an expected debt service coverage ratio comfortably greater than 1.0 times after the project's financial projections are subjected to rigorous, but still reasonable, stress tests. Lenders focus on the debt to equity ratio to satisfy themselves that both the lender and the sponsor have money at risk. Lenders focus on the owner's return on investment, not only at the time of the sponsor's investment, but also thereafter to make sure the sponsor will continue to be incentivized with a "carrot" to support the project if the project encounters difficulties. With merchant plants, in addition to these three financial measures, Moody's has also examined how wrong the power rate projections can be with the project still making debt service.

IX. COVENANTS

Lenders will require an extensive covenant package to protect the debt. The sponsor and the lender invariably heavily negotiate this package. Covenants will include business covenants, which proscribe and restrict the sponsor's project operation. Financial covenants will increase lender control to the extent certain financial tests have not been met. Lenders will require that project cash flow be handled according to a procedure and through accounts insuring that revenues are first used to pay operating costs, then debt service and then, only after certain debt service coverage and other tests are met, to provide distributions to the sponsors. Lenders will require debt service reserves, maintenance reserves and other reserves. Reporting covenants will require regular financial statements and other project-specific reports. The lenders will also require control over change in ownership to the extent the sponsor wishes to sell all or a portion of the project.

X. LENDERS' CAUTION

You may wonder why lenders exercise such caution, pursue such rigorous due diligence and require such control. The reason is that all of the current project lending institutions have, at one time or another, lost money lending to projects. In the late 1980's and very early 1990's project lenders were less cautious with regard to structure, documentation, business arrangements and new technology. Certain projects eventually failed, and the project finance community learned its lesson. Writing off all or a portion of a loan can significantly reduce a project lending area's profitability. Assuming that a lender makes a one percent profit on a project loan--not out-of-the-market during the past ten years--writing off a $50 million loan would equal losing an entire year's profits on a portfolio of fifty $50 million loans. Obviously, the project lending community has developed a long memory with regard to projects, which failed and now rigorously attempts not to repeat its mistakes.

XI. COAL UPDATE

Recognizing that this is a clean coal conference, I'd like to make a few comments about coal-fired power plants. As you would expect, we are very comfortable with existing coal-fired technology. With regard to the developing clean cold technology, however, my previous comments on assessing new technology risk would apply. Moody's has not yet been presented with a financing for a clean coal technology power plant. Nearly all of the power plant construction financings we and the bank market have seen over the past few years have been for gas-fired power plants. We have seen only one new coal-fired plant financed over the past year--Tractebel's coal-fired fluidized bed Choctaw Project. We, of course, have recently reviewed financings for coal-fired plants, which have been sold as part of the ongoing electric industry deregulation. A well-known example would be Edison Mission's Homer City. Although power rate consultants program into their computer models the choice of building a coal plant instead of a gas plant to supply future capacity needs, their computer models invariably choose gas plants because of lower capital cost and permitting ease. Our operating assumption is, therefore, that new generation over the next 15 to 25 years will be supplied overwhelmingly by simple cycle or combined cycle gas-fired plants.

XII. CONCLUSION

I hope you've found this discussion helpful. Project lenders employ rigorous--but reasonable--analysis when choosing among projects to finance and analyzing a particular project's risks. Lenders will only finance projects, which they believe have a very good chance of repaying the financing according to schedule. Again, as I said at the beginning of this talk, only projects, which are well structured and make money will secure financing. We look forward to the first clean coal projects' approaching the debt markets.

Thank you.

INDUSTRIAL CHAMPIONS, TECHNOLOGY DEVELOPERS AND KNOWLEDGEABLE LEGISLATORS: KEY ACTORS BEHIND THE SUCCESSFUL INTRODUCTION OF CLEAN COAL TECHNOLOGIES

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ABSTRACT

Technology users, such as utilities and other industries normally want to see that a new technology, however promising it may seem, is well proven before they are prepared to apply it for their own purposes. Equipment suppliers, on the other hand, need to get their new technologies demonstrated at a relevant scale. That can only happen if individuals in the user community act as champions, who are prepared to take or at least share the risk of building a first-of-a-kind plant. In fact, one plant is in most cases not enough to secure commercial deployment of a new clean coal technology.

This is a chicken and egg situation, which requires co-operation between technology developers and users. It is a necessary requirement for the introduction of new clean coal technologies in the power generation field. But it is not enough! Legislators also have a key role! The fact that markets, economies and environmental issues increasingly become more competitive as well as global means that the legislators must widen their perspectives in order to be able to contribute to an appropriate future use of clean coal technologies.

Some examples will be given from countries and technology developments where this works, and where it doesn't!

FULL PAPER UNAVAILABLE AT TIME OF PRINTING

PANEL SESSION 3

Issue 3: Coal in Tomorrow's Energy Fleet: Pressures and Possibilities

A Roadmap for Coal-Based Generation

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7th Clean Coal Technology Conference

Knoxville, Tennessee

June 23, 1999

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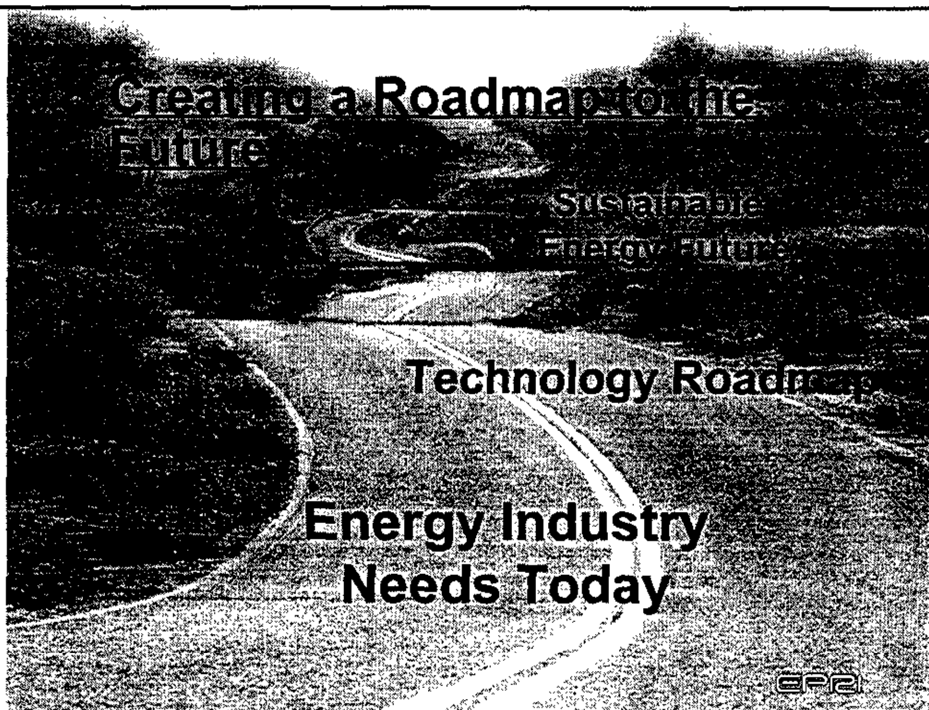
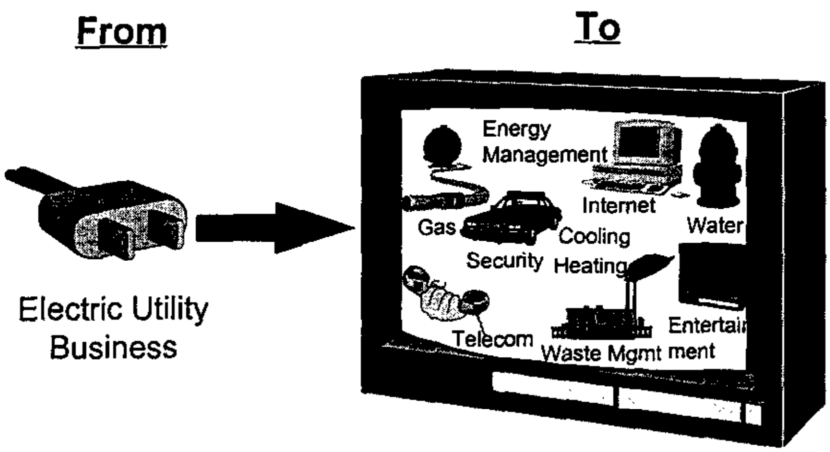
EPRI



The Changing Electricity Enterprise



Electric Utility Business

Electricity Enterprise

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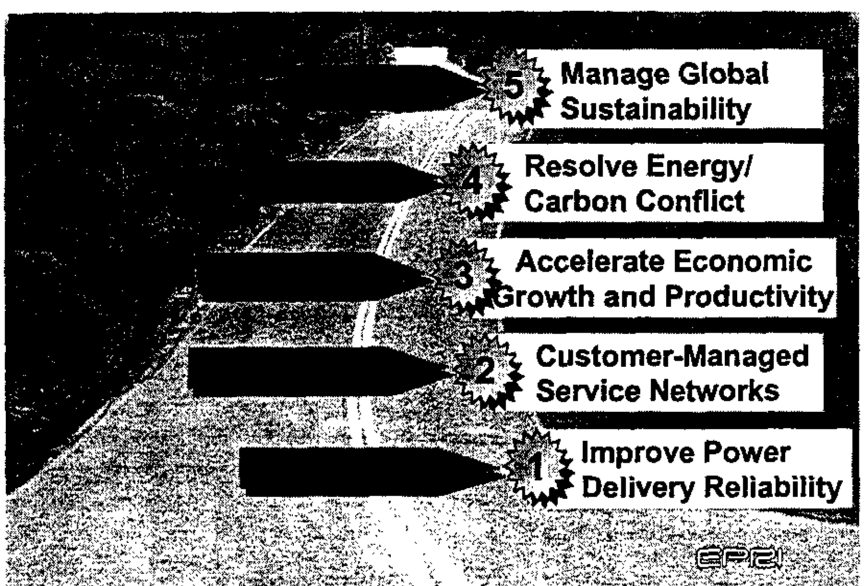
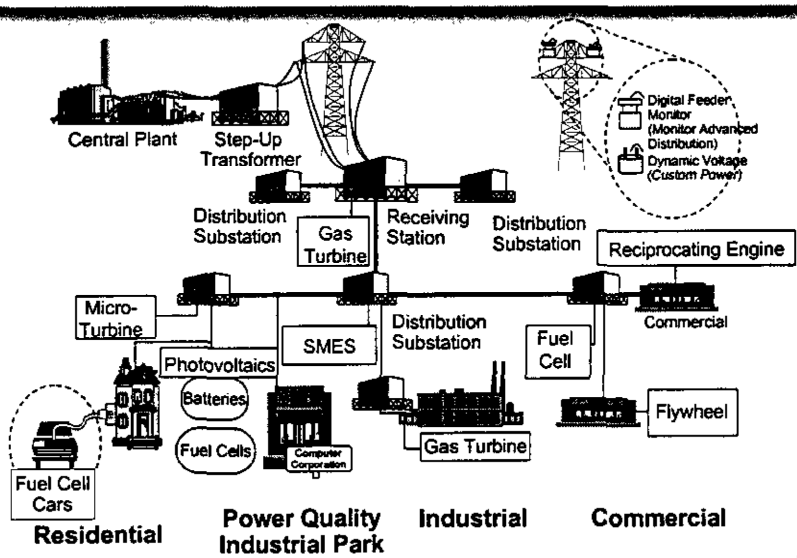
Building the Electricity Technology Road



Changing Role of Central Generation in the New Service-Based Industry



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Risks of Investing in Coal-Based Generation

Areas of concern

- High cost of coal-based generation
- Uncertainties regarding environmental regulations
- Vulnerability to climate change regulation
- Coal is out of favor -- natural gas has momentum

Mitigating factors

- Growing recognition of importance of fuel diversity
- Sequestration technology reduces risk to investors
- Overseas markets for coal-based generation

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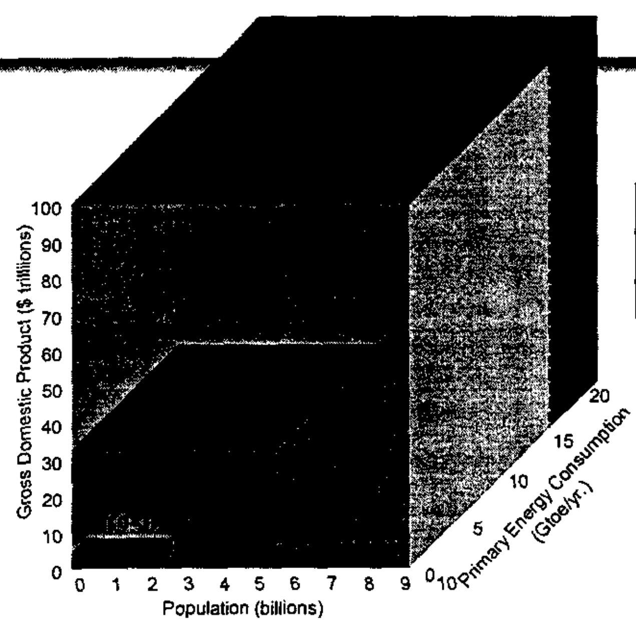
The Global Sustainability Challenge

Factors

- Between 1950 and 2050 global population will quadruple and urbanization will grow even faster
- Electricity is key to sustainable growth in productivity, agriculture, fresh water and emission reduction
- Decarbonization leading to an electricity/hydrogen energy system is achievable, but requires an innovative portfolio of generation options

The Global Trilemma Box



25% reduction in primary energy consumption through electrification

What 10,000 GW of Global Generating Capacity Means

- Tripling current world power plant capacity
- Adding 200,000 MW/yr
- Investing $100-150 billion/yr

It's equivalent to:

- < 5 years of current world automobile engine production
- Less than 0.3% of world GDP
- Less than the world spends on cigarettes, etc.

It can and must be done!

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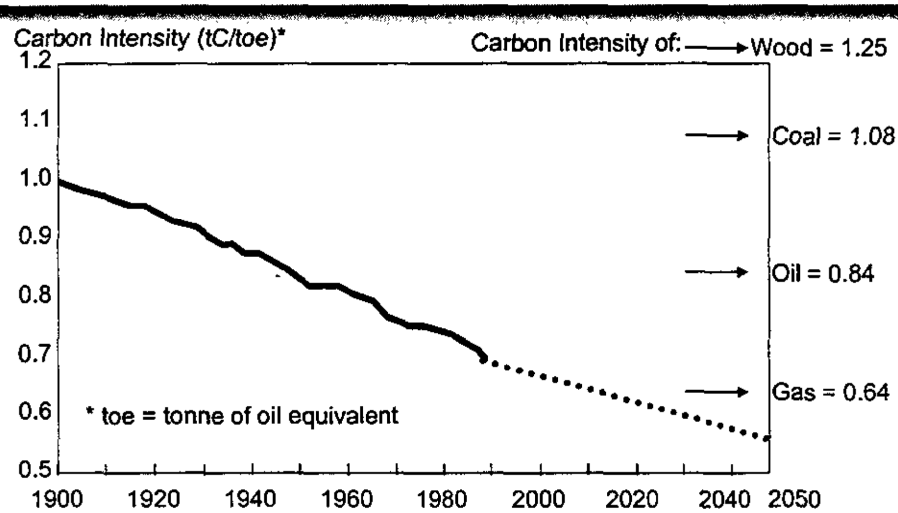
Carbon Intensity of World Primary Energy, 1900-2050



Source: National Academy of Engineering, 1997

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Broad Portfolio of Options

- No simple, single solutions
- Optimum technology choice varies from place to place
- Fossil, nuclear, renewables, central and distributed/dispersed options will all be needed
- Breakthroughs needed

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Technology - Foundation for Continued Use of Coal

Targets for next generation coal technologies

Performance Targets	Today	2010	2020
Capital Cost, $/kW	900-1300	800	800
Efficiency, % HHV	40	45	50-60
SO2, removal %	95	97	99
No_x lbs/mmbtu	0.1-0.3	0.08	0.05
HAPs (Hazardous Air Pollutants)	Define goals	Meet goals	Meet goals
Waste Utilization, %	15-30	50-75	100

Source: CURC

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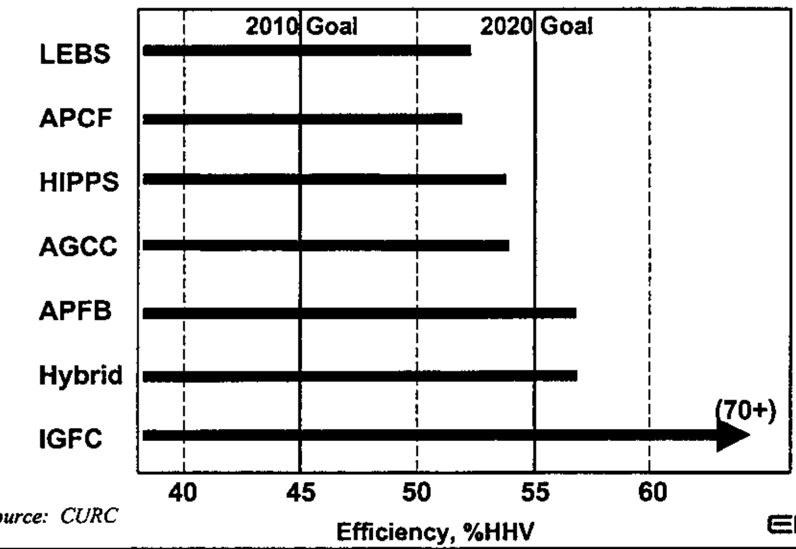
Efficiency Goals for Coal-Based Generation



Source: CURC

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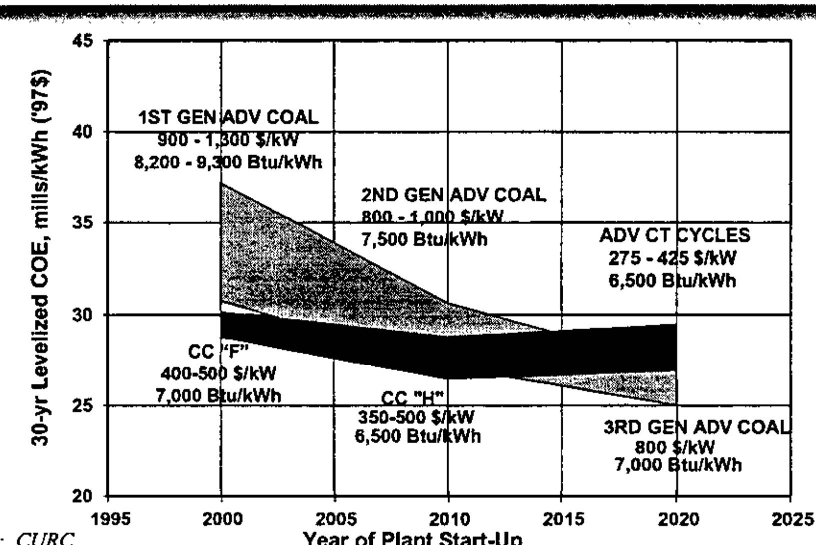
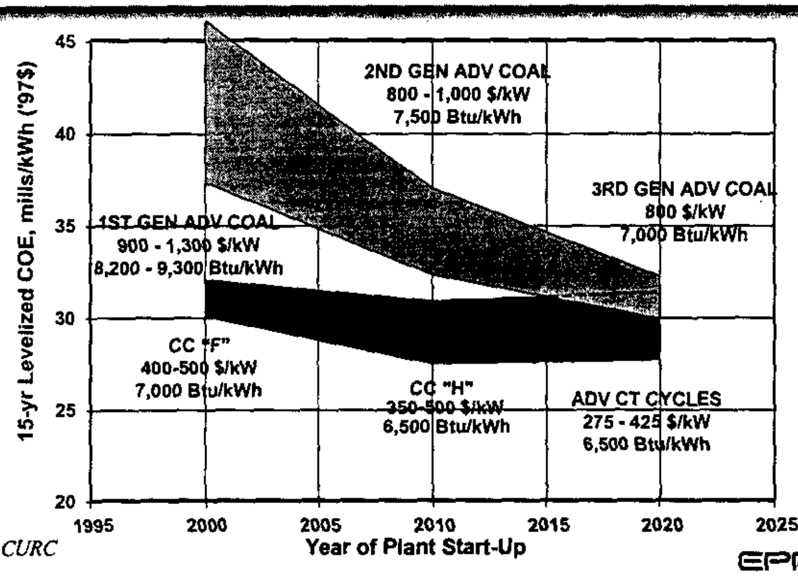
30-Year Levelized Cost of Electricity for Coal- and Gas-Based Power Generation



Source: CURC

EPRI

15-Year Levelized Cost of Electricity for Coal- and Gas-Based Power Generation



Source: CURC

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Cross-Cutting Enabling Technologies

Technology	2010	2020
High Temperature/ High Pressure Filters		
AGCC	1000°F reducing	1500°F reducing
APFB	1600°F oxidizing	1700°F oxidizing
HIPPS	1100°F reducing	1500°F reducing
IGFC	NA	1000°F reducing
Combustion Turbine		
AGCC	2750°F ATS	Advanced Cycle
APFB	2750°F, adv. combustor	Advanced Cycle
HIPPS	NA	2750°F
Steam Cycle Materials		
APFB	NA	New alloys, 1300°F
APC	Ferritics, new alloys	New alloys, 1300°F
HIPPS	NA	New alloys, 1300°F
HAPS	Address issues for all technologies	Address

Source: CURC

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Cost-Effective CO_2 Sequestration

Project: CO_2 mitigation with *the aid of carbonic* anhydrase

Existing Process: CO_2 removal and concentration step for exhaust gases

New Process: Enzyme-catalyzed scrubbing of exhaust gasses at ambient conditions

Savings: Offsets possible future legislation

Benefit: Environmental friendly; permanent sequestration

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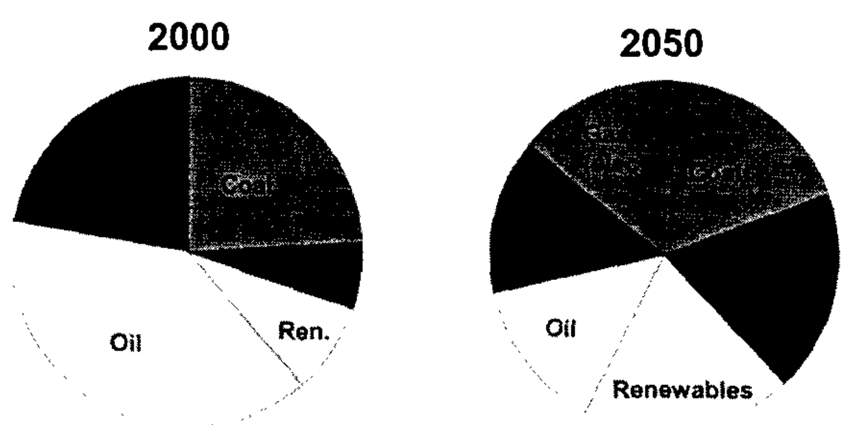
Coal Can Account for 20% of Primary Energy in a Balanced 2050 Portfolio



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Summary: A Coal Roadmap

- Coal-based generation is a critical part of the eventual transition to carbon-free generation
- Coal can contribute ~20% of world primary energy (>3 Gt of oil equivalent) through 2050
- Broad-based research program is needed now to increase the real and perceived value of coal
- Special emphasis on low cost, very high efficiency, high electrification, sequestration as a hedge against CO_2 emissions limits

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VISION 21: ADVANCED ENERGY PLANTS FOR THE 21ST CENTURY

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ABSTRACT

It is highly likely that the U.S. will need to rely on fossil fuels for the major share of its electricity and transportation fuel needs well into the 21st century. The wisest policy for the long-term may be to utilize a balanced mixture of energy resources, including fossil fuels and renewables, rather than any single resource. Currently, the U.S. electric power industry is undergoing a period of unprecedented change driven largely by electric utility restructuring, the availability of relatively low-cost natural gas, environmental regulation, and concerns about global climate change. The implications of these drivers on the future economic competitiveness and prosperity of the U.S. cannot be underestimated. Technological innovation may well be the best, and perhaps the only way, to address the coming challenges to our electric power and fuel supply infrastructure, and to ensure that we continue to have the plentiful supply of affordable energy upon which a robust economy depends.

Vision 21 is a government/industry/academia cost-shared partnership to develop the technology basis for integrated energy plants that will, early in the 21st century, result in the deployment of ultra-clean plants that produce electricity and "opportunity" products. Vision 21 plants will use fossil fuel feedstocks in combination with other domestic resources, e.g., biomass, municipal waste, and petroleum coke. Opportunity products could include clean liquid transportation fuels, steam, high-value chemicals, synthesis gas, and hydrogen. Vision 21 plants will effectively remove environmental constraints as an issue in the use of fossil fuels: emissions of traditional pollutants, including smog- and acid rain-forming species, will be near zero and the greenhouse gas, carbon dioxide, will be reduced 40-50% by efficiency improvements, and reduced to zero if coupled with sequestration.

This paper introduces the Vision 21 concept and the performance objectives for future Vision 21 plants, provides examples of Vision 21 system configurations, describes the current status of the key technologies that will be needed for Vision 21, and the plans for developing these technologies.

I. INTRODUCTION

The U.S. electric power industry is currently undergoing a period of unprecedented change driven largely by electric utility restructuring, the availability of relatively low-cost natural gas, environmental regulation, and concerns about global climate change.

As the power industry deregulates, utilities which were heretofore protected against competition and guaranteed returns on their investments are now being forced to compete for market share and profits. Deregulation is changing the way the industry operates and invests in new facilities and technology. In a market-driven environment, power plant owners must be concerned about profitability and ability to finance new investments. This may cause owners to avoid technical risk and favor low capital cost alternatives, especially when such alternatives are coupled with a fuel supply contract for a period long enough for the investment to be recovered.

Today's low cost of natural gas is causing power producers to favor low capital cost turbines over relatively high cost coal-fired boilers for new capacity. The Energy Information Administration projects that 363 gigawatts (GW) of new generation capacity will be needed by 2020. Of this, only 9% will be coal-fired, 88% will be natural gas-fired combustion turbine and combined-cycle, and 3% will be renewable technologies (mainly wind and biomass gasification).

The Clean Air Act of 1970 and subsequent amendments have brought about major reductions in emissions of the acid gases, i.e., sulfur and nitrogen oxides, and particulate matter for new coal-fired power plants. Existing plants are increasingly being required to cut emissions. Moreover, renewed concern about fine particulate matter and its precursors (nitrogen and sulfur oxides), trace element emissions (especially mercury), and ozone (and its nitrogen oxides precursor) have created new pressures for cleaner plants. These pressures are unlikely to ease in the future; rather, each new generation of power plants will be expected to be cleaner than the last.

Perhaps the biggest change will be driven by concern over global climate change. Emissions of greenhouse gases, especially CO_2 from fossil fuel use, may need to be reduced in the future. Although a portion of this reduction may be achieved through emissions trading and credits for investing in emissions reduction projects in developing countries, it is likely that substantial reductions in carbon emissions will be necessary. Increasing the efficiency of power generation is a step in the right direction, but a technological solution that would provide reductions in carbon emissions sufficient to eliminate concerns about climate change has yet to be identified.

The implications of these drivers for the future economic competitiveness and prosperity of the U.S. cannot be underestimated. Our economic future depends on a supply of affordable electricity to run our factories and heat and light our offices and homes and on clean fuels for transportation. Predictions have been made about how limits on carbon emissions will constrain our economy. However, predictions often underestimate the impacts of technological innovation. Indeed, technology innovation is the best way to address the coming challenges to our electric power and fuel supply infrastructure.

Fossil fuels will continue to play a major role in supplying electricity and transportation fuels well into the 21st century. Although the current situation in the U.S. favors natural gas, for the long-term the wisest policy is to depend on a diverse mixture of energy sources, including coal, gas, oil, biomass and other renewables, nuclear, and "opportunity" resources. On the other hand, by focusing our activities now and taking the lead on developing the needed technology, we will not only meet the energy and environmental challenges we face, but at the same time make our economy stronger.

II. VISION 21

The current DOE Fossil Energy R&D Program is addressing the development of 1) cost-effective power systems, based on both coal and natural gas individually and in combination, that are substantially cleaner and more efficient than systems in use today, and 2) technology for producing alternative sources of liquid transportation fuels that are cost-competitive with equivalent petroleum products. Different kinds of power systems are being developed more or less independently, each based on a different technology: advanced pulverized coal combustion, gasification combined cycle, pressurized fluidized bed combustion, indirectly fired cycles, advanced turbine systems, and fuel cells. Activities in fuels technologies include indirect and direct liquefaction, coprocessing coal with opportunity and "waste" materials to make liquid fuels, and natural gas to liquids processing. Each technology development effort has its own set of objectives and time schedules for development and deployment.

To achieve radical improvements in the performance of fossil fuel-based power systems and to virtually eliminate environmental issues as a barrier to fossil fuel use will require both new energy conversion technology and new systems that incorporate the technology. Any of the technologies under development cannot *individually* achieve the efficiency, environmental, and cost goals that will be needed in the early decades of the 21st century. Rather, we need a new approach that allows us to integrate power and fuel system "modules" into systems that achieve the needed level performance at costs we can afford. *The key difference between Vision 21 and our current R&D portfolio is that Vision 21 focuses on systems that integrate multiple technologies in order to achieve "leapfrog" improvements in performance and cost. Other differences are Vision 21's emphasis on market flexibility, multiple feedstocks and products, and industrial ecology.*

Vision 21 is a government-industry-academia collaboration to develop technology that will *effectively remove all environmental concerns associated with the use of fossil fuels* for producing electricity and transportation fuels. The approach is to develop and integrate high-performance technology modules to create energy plants that are sufficiently powerful to meet our energy needs in the 21st century, and yet flexible enough to address site-specific market applications. Vision 21 builds on a portfolio of technologies already being developed, including clean coal combustion and gasification, turbines, fuel cells, and fuels synthesis, and adds other critical technologies and system integration techniques. Vision 21 is one of the means by which the Department of Energy is carrying out its role to help maintain our nation's economic prosperity by ensuring a future supply of affordable, clean energy.

Objectives/Performance Targets for Vision 21 Plants

The primary objective of the Vision 21 program is to effectively remove all environmental concerns associated with the use of fossil fuels for producing electricity, transportation fuels, and high-value chemicals. The specific performance targets, costs, and timing for Vision 21 plants are:

Efficiency-Electricity Generation	60% for coal-based systems (based on fuel HHV); 75% for natural gas-based systems (LHV) with no credit for cogenerated steam*
Efficiency-Combined Electricity/Heat	overall thermal efficiency above 85% (HHV); also meets above efficiency goals for electricity*
Efficiency-Fuels Only Plant	when producing fuels such as H_2 or liquid transportation fuels alone from coal, 75% fuels utilization efficiency (LHV)*
Environmental	near zero emissions of sulfur and nitrogen oxides, particulate matter, trace elements, and organic compounds; 40-50% reduction in CO_2 emissions by efficiency improvement; 100% reduction with sequestration
Costs	aggressive targets for capital and operating costs and RAM; products of Vision 21 plants must be cost-competitive with market clearing prices when they are commercially deployed
Timing	major benefits, e.g. improved gasifiers and combustors, gas separation membranes, begin by 2006 or earlier; designs for most Vision 21 subsystems and modules available by 2012; Vision 21 commercial plant designs available by 2015

* The efficiency goal for a plant cofeeding coal and natural gas will be calculated on a pro-rata basis. Likewise, the efficiency goal for a plant producing both electricity and fuels will be calculated on a pro-rata basis.

Other Characteristics of Vision 21 Plants

Vision 21 plants:

- must involve a conversion of energy such as coal or natural gas to high-value products such as electricity or transportation fuels. Steam or heat may be secondary products. Conventional petroleum refineries are excluded, as are coal slurry preparation plants.

- will likely be large stand-alone energy facilities, generally larger than 30 MWe or with equivalent energy output if other products such as liquid fuels are produced (not including thermal credit for steam or waste heat.)

- may be central station facilities or be located at or near the consumer's site (e.g., a large industrial consumer). Small distributed power generation or fuel production is not considered to be part of Vision 21, although near-term spin-off applications for distributed power may occur.

- will use fossil fuel based feedstocks, either alone or in combination with biomass and/or opportunity feedstocks such as petroleum coke, refuse-derived fuel (RDF), municipal solid waste (MSW), and sewage sludge. Biomass-only plants are excluded.

- will emphasize market flexibility, including multiple feedstocks and products.

- will be composed of two or more modules combined with "smart" systems integration techniques.

- that capture and concentrate CO_2 for sequestration purposes may include a theoretical credit for the enthalpy of the pressurized CO_2 "product" in the efficiency calculation.

Example of a Vision 21 Plant

Figure 1 shows an artist's rendition of a Vision 21 plant. The plant features modular design and uses multiple feedstocks to make a market driven product slate. Coal and opportunity feedstocks are gasified using oxygen produced with a low-cost air separation membrane. The fuel gas is cleaned and then a second membrane is used to separate hydrogen. Carbon monoxide in the fuel gas may be shifted to CO_2 and the CO_2 sequestered if necessary. Electricity is generated with a fuel cell using the hydrogen and with a gas turbine using the energy in the fuel cell exhaust. Heat remaining in the turbine exhaust is used to generate steam for process heating. A portion of the fuel gas is diverted for the production of liquid fuels and high-value chemicals.

Vision 21 Technologies

Critical technologies have been identified that will play a key role in Vision 21. These technologies have been divided into two groups, enabling and supporting.

Enabling technologies are those upon which the subsystems, or modules, that form the building blocks of a Vision 21 plant depend. Some enabling technologies, like gasification and advanced combustion, are already under development and some have been, or are being, demonstrated in the Clean Coal Technology Demonstration Program. The enabling technologies, their current status, and the research and development needs are:

- **Oxygen Separation Membrane** - *Current status*: Membranes are being tested at the laboratory scale. These high-temperature (1500°F) membranes could start to replace conventional energy intensive cryogenic separators by 2007. *Next step*: Test for stability and chemical resistance, scale-up, component integration, verify longevity of membrane.

Long-term Vision 21 needs: Cost reduction, process integration, verify survivability of membrane system in a commercial application.

- **Hydrogen Separation Membrane** - *Current status*: Membranes are being tested at the laboratory scale. These membranes, which should be available for testing at commercial scale by 2009, will allow high-temperature separation of hydrogen from syngas for use as a fuel or chemical feedstock. *Next step*: Test for stability and chemical resistance, scale-up, component integration, verify longevity of membrane. *Long-term Vision 21 needs*: Cost reduction, process integration, dependability, verify survivability of membrane system in a commercial application.

- **High-Temperature Heat Exchanger** - *Current status*: Metal alloy heat exchangers, capable of 2000°F operation, are being tested at process development unit scale and will be available by 2005. Higher temperature (i.e., 3000°F) ceramic heat exchangers are in the materials R&D stage with commercial introduction of large-scale units expected by 2020. High-temperature radiant heat exchangers are required for Vision 21, especially for embodiments that use indirectly fired cycles. Gas exit temperatures above 2700°F are needed to meet Vision 21 efficiency targets. *Next step:* Assess materials and system designs. *Long-term Vision 21 needs:* Develop designs and acceptable-cost fabrication methods for large-scale ceramic heat exchange components; prove system ability to withstand multiple cold starts and temperature spikes.

- **Fuel Flexible Gasification** - *Current status*: Petcoke has been test fired in industrial- and utility-scale gasifiers and combustors. Biomass, municipal waste, and many other opportunity feedstocks have had only limited or no test experience. Fuel flexibility is needed to allow use of low-cost feedstocks and to take advantage of synergies with other industrial processes (e.g. pulp and paper, oil refining, sewerage treatment plants). *Next step*: Characterize feedstocks, assess handling and chemistry issues. *Long-term Vision 21 needs:* Prove feed system reliability, verify ability to control operating parameters to ensure zero waste discharge with variable feedstocks.

- **Gas Stream Purification** - *Current status*: Warm gas (700-1000°F) clean-up systems are being tested at utility scale. High-temperature (>1000°F) systems with ultra-pure gas streams will be ready for commercial-scale testing by 2008. These higher temperature systems enable the use of hydrogen membranes and improve efficiency by eliminating the need to cool and then reheat gas streams. *Next step:* Scale up, verify durability of materials for catalysts and filters, improve high-temperature sorbents. *Long-term Vision 21 needs:* Reduce cost of catalyst and filter systems, increase longevity of materials and systems.

- **Advanced Combustion Systems** - *Current Status:* High-temperature, low-NOx combustors have been developed and tested at pilot-scale under the Low Emission Boiler Systems (LEBS), Advanced Pressurized Fluidized Bed Combustion (APFBC), and High Performance Power Systems (HIPPS) programs. There is no current work on combustion in CO_2/O_2 mixtures, needed to adapt these systems for CO_2 separation and sequestration. *Next step:* Scale-up low-NOx combustion systems to small commercial scale under LEBS; conduct lab-scale studies to assess combustion of fuels in CO_2/O_2; investigate isothermal compression. *Long term Vision 21 needs:* Design higher temperature combustors that will burn fuels in CO_2/O_2 mixtures and recycle CO_2 exhaust. Goal is to have commercially ready designs by 2015.

- **Fuel Flexible Turbines** - *Current status*: F class turbines are currently being operated on syngas, the first of the G class turbines are starting operation on conventional fuels and the first advanced turbine systems (ATS) turbines will be tested on natural gas by 2000. *Next step:* Integration studies and technology development to integrate ATS technology into Vision 21 systems. *Long-term Vision 21 needs:* Full-scale test of ATS fuel flexible turbine suitable for Vision 21 applications.

- **Fuel Cells** - *Current status*: Atmospheric pressure fuel cells are currently available in the several kilowatt to several megawatt size range (at a cost of about $2000 - 3000/kW). Pressurized, cascaded fuel cells, and fuel cell/turbine systems, will be ready for commercial use by 2015. *Next step:* Identify optimal hybrid system, reduce cost by a factor of ten through improved manufacturing techniques and systems integration. *Long-term Vision 21 needs:* Continue cost reduction, verify commercial scale system stability and reliability.

- **Advanced Fuels and Chemicals Development** - *Current status*: Catalysts for producing some fuels and chemicals are available for use at pilot- and commercial-scale. Adaptation and evolution of current systems to operate in a Vision 21 plant will be completed by 2005. *Next step:* Identify optimum catalysts and systems, and scale up. *Long-term Vision 21 needs:* Cost reduction.

Supporting technologies are cross-cutting technologies that are common to many Vision subsystems and components and may be important in applications other than Vision 21. The supporting technologies are:

- **Materials** - *Current status*: New alloys and ceramics, suitable for use at high temperatures in corrosive environments, are being developed for Vision 21 subsystems and components. *Next step*: Continue to develop advanced alloys and ceramic materials which allow for improved performance. Develop fabrication technology, e.g., joining, welding. *Long-term Vision 21 needs:* Technology for fabricating, at acceptable cost, large-scale ceramic components for Vision 21 applications. Demonstrate reliability of such large-scale ceramic components.

- **Advanced Computational Modeling, Virtual Demonstration** - *Current status*: The use of virtual demos is already being realized in other industries as a cost-effective way to reduce the number of scale-up steps and cut development and design costs. *Next step*: Refine and improve existing subsystem models and develop new models where needed. Develop a computer simulation to "demonstrate" integration of subsystem models. *Long-term Vision 21 needs:* Develop computer simulations for complex plants, including co-production plants. To the extent possible, verify that the simulator is accurate by comparing to actual facilities.

- **Advanced Controls and Sensors** - *Current status*: Gasifiers and other equipment with instrument-hostile environments generally rely on indirect and calculated (from information at other locations in the process) measurements. Advanced sensors and controls are needed to monitor process conditions directly to increase process efficiency, reliability, availability, and to detect early signs of failure. *Next step*: Develop and test robust sensors and intelligent control systems. *Long-term Vision 21 needs:* Test control systems and sensors in a commercial environment.

- **Advanced Environmental Control Technology-** *Current status:* Technology improvements for the existing fleet are enabling power generators to meet current and forecasted regulations. *Next Step:* Define control technology requirements for Vision 21 plants and extend performance of existing technologies to meet these requirements, if possible. *Long-term Vision 21 needs:* Develop acceptable-cost technologies that effectively control all pollutants from fossil fuels to mitigate any environmental consequences.

- **Advanced Manufacturing and Modularization** - *Current status*: Most large industrial and utility fossil fuel plants are designed on a site-by-site basis. *Next step*: Design modular packages in several fixed size ranges to reduce design and production costs. *Long-term Vision 21 needs:* Develop methodology for incorporating modular design and construction practices into complex Vision 21 plants.

III. EXAMPLES OF VISION 21 SYSTEMS

Several configurations of Vision 21 systems have been analyzed to determine whether the thermal efficiency targets can be met and, if so, what levels of performance would be required from the different subsystems and components. The configurations studied were developed from familiar "building blocks," including gasifiers, combustors, fuels cells, combustion turbines, and steam turbines; however, these systems are examples and there is no suggestion that they are likely configurations for future Vision 21 plants.

Gasification/Gas Turbine/Fuel Cell Cycle

A high efficiency gasification/gas turbine/fuel cell hybrid cycle was investigated (Figure 2). The heat and mass balance indicates that it is thermodynamically feasible to achieve 60% efficiency (HHV) using coal as the fuel. The gas turbine, fuel cell, and gasifier technology selected for the cycle represent the state-of-the-art in our current development programs. Many of the subsystems and components in Figure 2 have not been tested at the indicated scales or operating conditions. The challenge is to integrate the subsystems at the correct sizes and conditions, simplify the cycle, develop a control strategy and the means to implement it, and reduce cost.

The design shown produces 560 MW (gross) or 520 MW (net) power. The fuel is Illinois No. 6 coal containing 2.5% sulfur. The coal is gasified in an entrained bed gasifier operating at 15 atmospheres pressure. A cold gas conversion efficiency of 84% is assumed. The fuel gas is cleaned, cooled, and desulfurized before entering a solid oxide fuel cell (SOFC) operating at 15 atm. and 1000°C. A portion of the gasifier fuel gas is reduced in pressure through an expander/turbine before entering a second, low pressure, SOFC operating at 3 atmospheres. Ninety percent of the fuel constituents are converted within the cell chambers to produce electricity. The remaining fuel is combusted with the oxidant exhaust streams from the SOFC cathodes to boost the heat energy available for use in the two cascaded turboexpanders. Heat from the turbine exhausts and from the fuel gas cooler is used to generate steam for a reheat steam cycle operating at 1450psi and 538°C. Of the 560 MW gross power, 33% is provided by the high-pressure SOFC, 21% by the low-pressure SOFC, 25% from the turboexpanders, and 21% from the steam turbine.

Combustion/Gas Turbine/Fuel Cell Cycle

Figure 3 shows a combustion/gas turbine/fuel cell cycle that also achieves a theoretical efficiency of 60%. In this system, both the partial gasifier and fluidized bed use coal and oxygen, the latter being provided by a conventional air separation unit. The result is that the exhaust from the system contains only CO_2 and water, making the system readily adaptable to CO_2 recovery and sequestration. Steam is used to moderate temperatures in the pressurized fluidized bed combustor (PFBC) and in the topping combustor. Fuel gas from the partial gasifier, after cleaning, goes to a SOFC, which generates about 8% of the 350 MW gross power. Combustibles remaining in the SOFC exhaust are burned in the topping combustor, which is also used to raise the temperature of the PFBC flue gas. The hot, pressurized topping combustor exhaust is used in a turboexpander to produce about 40% of the power output. Steam produced from heat in the PFBC and the turboexpander exhaust is used in a steam cycle, producing 52% of the power output.

Indirectly Fired Cycle Bottoming Fuel Cell

Indirectly fired cycles do not require hot gas cleanup before the gas turbine because only clean air, or an alternative working fluid, contacts the turbine. Figure 4 shows a coal-fired indirectly fired cycle that bottoms a natural gas-fueled solid oxide fuel cell (SOFC). The energy in the SOFC exhaust is utilized in the HITAF (high-temperature air furnace). Coal is also burned in the HITAF to heat air for the turbine and to generate steam for a steam cycle. The efficiency of this cycle, with gas turbine inlet conditions of 20 atm. and 1400°C, is 62% (HHV). About 30% of the power is generated by the fuel cell. Coal provides 65% of the fuel input and natural gas provides the remaining 35%.

Figure 5 is a similar indirectly fired cycle except that an air separation unit (ASU) has been added in order to make the cycle "sequestration ready," i.e., the exhaust contains only CO_2 and water. Nitrogen from the ASU serves as the turbine working fluid whereas the oxygen is used in the fuel cell and in the HITAF. As in the air-blown cycle, coal still provides 65% of the total heat input but the cycle's thermal efficiency is lower, 53% (HHV). The main reasons for the lower efficiency are the energy required by the ASU and the reduced mass flow through the turbine.

Humid Air Turbine and Cascaded Humid Air Turbine

The above cycle configurations utilize fuel cells to help achieve their high theoretical efficiencies. It is desirable to identify high-efficiency cycles that do not require the use of fuel cells. Two promising candidates are the humid air turbine (HAT) cycle and the cadcaded humid air turbine (CHAT) cycle. Both of these cycles use low-temperature heat to humidify the gas turbine compressor discharge air. This results in a substantial increase in the mass flow of the turbine working fluid without increasing the compressor work requirement.

A simplified HAT cycle is shown in Figure 6. The saturator is similar to those used widely in the chemical process industry to add vapor to gas streams. The amount of water depends on the operating conditions but can be 25% or more by weight of the compressor discharge air. The limit is set by flame stability. The HAT cycle is based on an intercooled aeroderivative turbine but significant modifications to the combustor and to the turbine aerodynamics, cooling, and materials are required. Both power output and cycle efficiency are increased relative to the baseline turbine.

The simplified CHAT cycle shown in Figure 7 is essentially a reheat HAT cycle. A turbocharger is added that allows very high pressures in the saturator, e.g., 65-70 atmospheres, and higher mass fractions of water compared to the HAT cycle. The high-pressure humidified stream is heated in the HITAF, expanded to drive the turbocharger, reheated in the HITAF, and then heated further in the duct heater before expansion in the turbine. HAT and CHAT cycle efficiencies can be in the 55-60% (HHV) range, and perhaps higher. At comparable turbine inlet temperatures, the CHAT cycle furnishes more power than the HAT.

Examples of Coproduction Facilities

Table 1 lists U.S. facilities, operating and planned, that coproduce electricity, fuels, and chemicals. The number of plants is limited but deregulation should increase interest in coproduction facilities because of their potentially higher profitability compared with single product plants.

Worldwide, there are other coproduction facilities. Notable are three integrated gasification combined cycle (IGCC) plants located at refineries in Italy that are scheduled to begin operations within the next year or two (Table 2). One driving force for these projects are new limits on the sulfur content of residual fuel oil used to generate electicity. The Italian state-owned power company, ENEL, the world's largest consumer of resid for power generation, is seeking alternatives to direct combustion. In each of the new projects, petroleum resid is gasified to produce electricity, syngas, hydrogen, and other products. ENEL purchases the electricity and the refinery gets valuable products, including syngas and steam.

Japan's "Vision 21"

Japan's version of Vision 21 is already underway. With the support of the Ministry of International Trade and Industry (MITI), Japan's Electric Power Development Company is investing $170 million in a pilot plant called EAGLE (for "coal Energy Application for Gas, Liquid, and Electricity") to show that gasification and gas cleanup technology can produce a gas suitable for fuel cells. The plant includes a 150 ton coal/day entrained flow, oxgyen-blown, gasifier and a wet, low-temperature, process for cleaning the fuel gas. Three years of operation are planned after the plant construction is completed in 2001. If a suitable fuel cell becomes available, the fuel cell would be added to the gasification/gas cleanup plant in order to demonstrate an integrated gasification fuel cell (IGFC) system. The most likely fuel cell candidate is a pressurized SOFC currently being developed by Mitsubishi Heavy Industries. A 10 kW version is currently being tested but scale-up to 18 MW in fuel cell capacity would be required for the EAGLE plant. If it is converted to an IGFC system, the plant would produce electricity at high efficiencies, estimated at 55-65%, with a triple cycle that uses fuel cells, gas turbines, and steam turbines.

IV. VISION 21 PLANS AND FUTURE ACTIVITIES

The Vision 21 program plan contains five program elements (Table 3). Planned activities include the development of subsystems, components, and design tools, and the concomitant modeling, analysis, and experimental work. The scale of the latter activities will range from laboratory-, bench-, and pilot-scale, up to and including scales needed to obtain data for demonstrating the feasibility of prototype and commercial-scale plants. Demonstration activities, the exact timing of which will depend on prevailing economic conditions and market forces, will be left to private industry. DOE's role will be to facilitate the transfer of the Vision 21 knowledge base to industry.

Actions are being taken to help ensure that the Vision 21 program meets the needs of our industry stakeholders, the public, and our nation's long-term interests. For example, a workshop was held in Pittsburgh in December 1998 to introduce the Vision 21 program rationale to industry and to obtain feedback. Further industry workshops are planned. In a separate ongoing activity, the National Research Council has assembled a committee of industry and academic leaders to assess the Vision 21 program and will provide recommendations.

To implement Vision 21, partnerships will be created with industry, universities, private and public R&D laboratories, and federal and state agencies. The Federal Energy Technology Center will issue a series of competitive solicitations, create consortia, and implement Cooperative Research and Development Agreements. Plans have been developed for the current transition period during which portions of the current DOE power systems and fuels program is being restructured into the Vision 21 program. Part of the current R&D program will continue independently of Vision 21. In general, activities that address longer-term technology development and that can lead to step-change or "breakthrough" advancements would become part of Vision 21. Shorter-term activities leading to near-term incremental improvements would continue separately.

Table 1. U.S. Coproduction Projects

Project	Feedstock(s)	Product(s)	Status
Exxon/Air Products (Baytown, TX)	petcoke	electricity, hydrogen	startup 2000
Dakota Gasification Corp. (Beulah, ND)	lignite	ammonia, phenol, naphtha, cresylic acid, liquid nitrogen, CO_2, xenon, krypton, ammonium sulfate	operating
North American Kraft Pulp, Kvaerner (Sweden), Air Products	black liquor	electricity, steam	
Minergy Corp. (Neenah, WI)	paper sludge, natural gas	electricity, steam, glass aggregates	operating since 1998
Applied Energy Systems (Poteau, OK)	coal	electricity, food grade CO_2	operating since 1991
Houston Lighting & Power (Houston, TX)	coal	electricity, methanol, urea	study
TVA Coproduction Project	coal	electricity, urea, sulfur	proposal

Table 2. Italian Refinery IGCCs

Project (location)	Participants	Feedstocks/Products	Technology	Status
SARLUX (Sardinia)	SARAS, ENRON	visbreaker residue/550 MW electricity, syngas, H_2, steam	Texaco gasifiers, GE turbines	startup 2000
ISAB (Sicily)	ERG Petroli, Edison Mission Energy	asphalt, tars/500 MW electricity	Texaco gasifiers, Siemens turbines	startup late 1999
API Energia (Falconara, Italy)	API and ABB	petroleum residues/280 MW electricity, steam	Texaco gasifiers, ABB turbine	startup late 1999

Table 3. Vision 21 Program Elements and Subelements

Program Elements	Program Subelements
I. Systems Analysis	a. Market Analyis b. Process Definition c. Process Evaluation d. Subsystem Performance Requirements e. Economic Analysis f. Subsystem Data Analysis and Model Development
II. Enabling Technologies	a. Gas Separation b. High-temperature Heat Exchangers c. Fuel-flexible Gasification d. Gas Stream Purification e. Advanced Combustion Systems f. Fuel-flexible Gas Turbines g. Fuel Cells h. Advance Fuels and Chemicals Development
III. Supporting Technologies	a. Materials b. Advanced Computational Modeliing and Development of Virtual Demonstration Capability c. Advanced Controls and Sensors d. Environmental Control Technology e. Advanced Manufacturing and Modularization
IV. Systems Integration	a. Systems Engineering b. Dynamic Response and Control c. Industrial Ecology
V. Plant Designs	a. Designs for Components and Subsystems b. Designs for Prototype Plants c. Designs for Commercial Plants d. Virtual Demonstration Capability

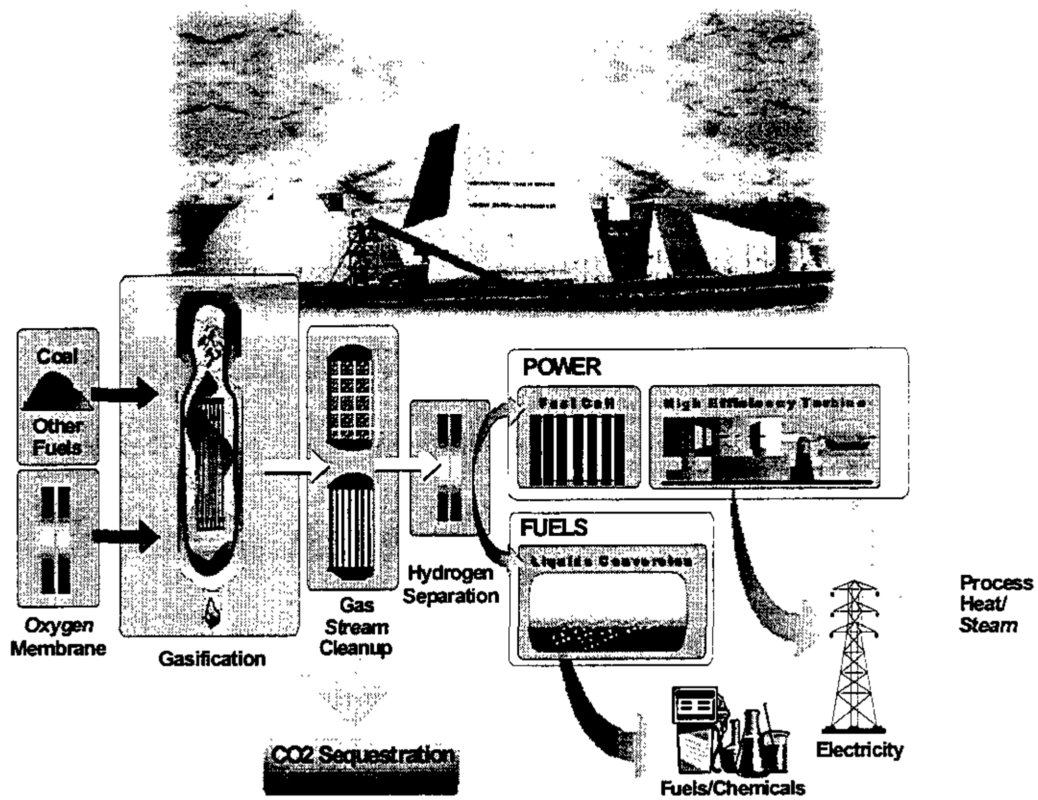

Figure 1. Example of Vision 21 plant

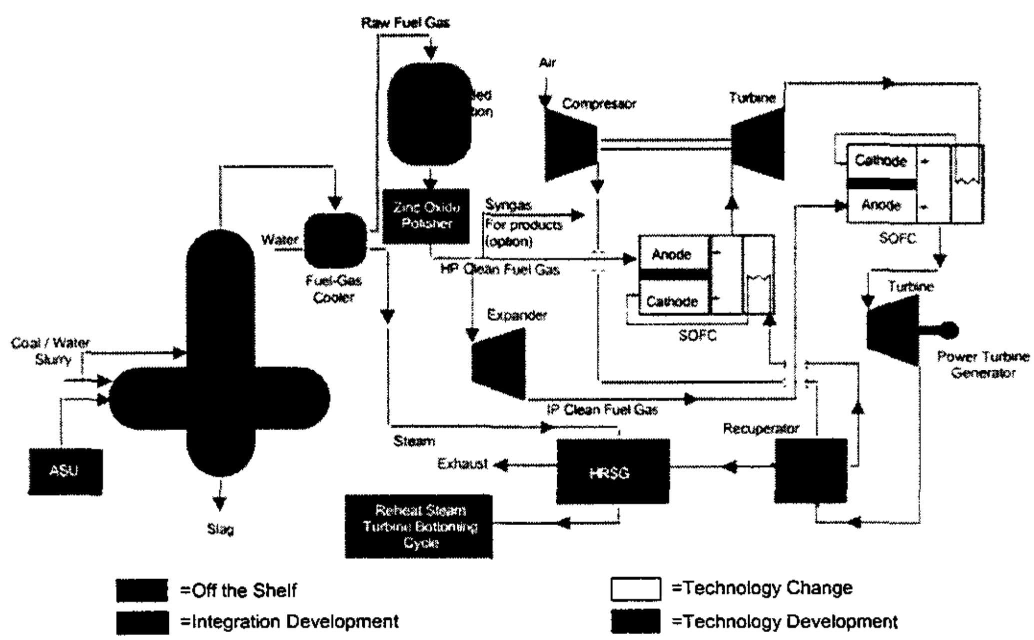

Figure 2. Vision 21 Gasification/Gas Turbine/Fuel Cell Cycle

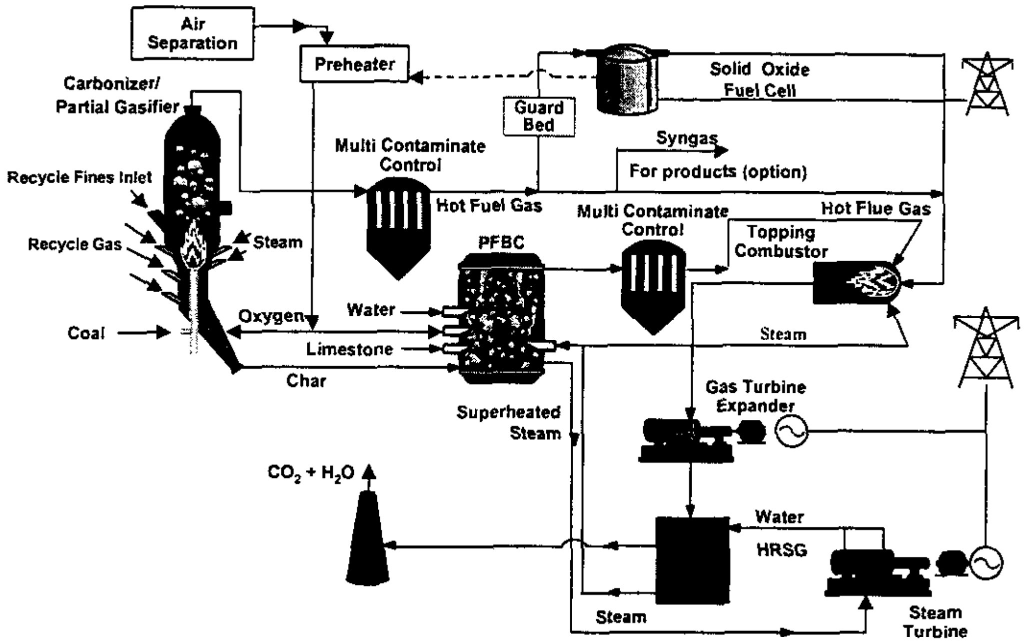

Figure 3. Vision 21 Combustion/Gas Turbine/Fuel Cell Cycle

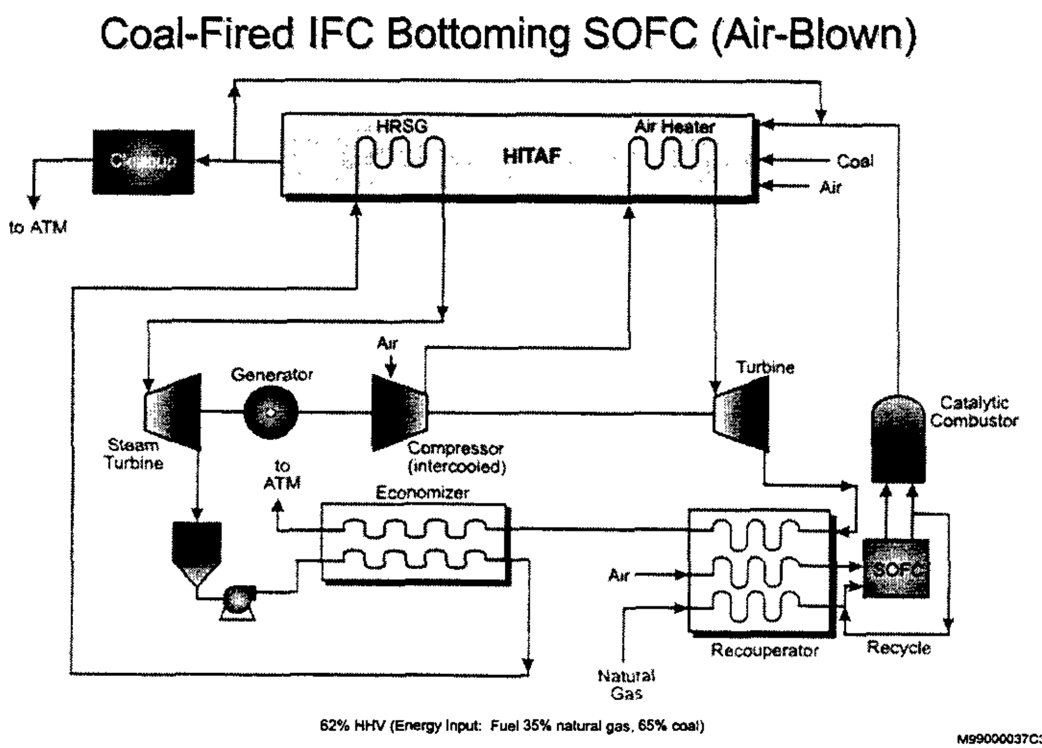

Figure 4. Combustion-Based Vision 21 System Without CO_2 Separation

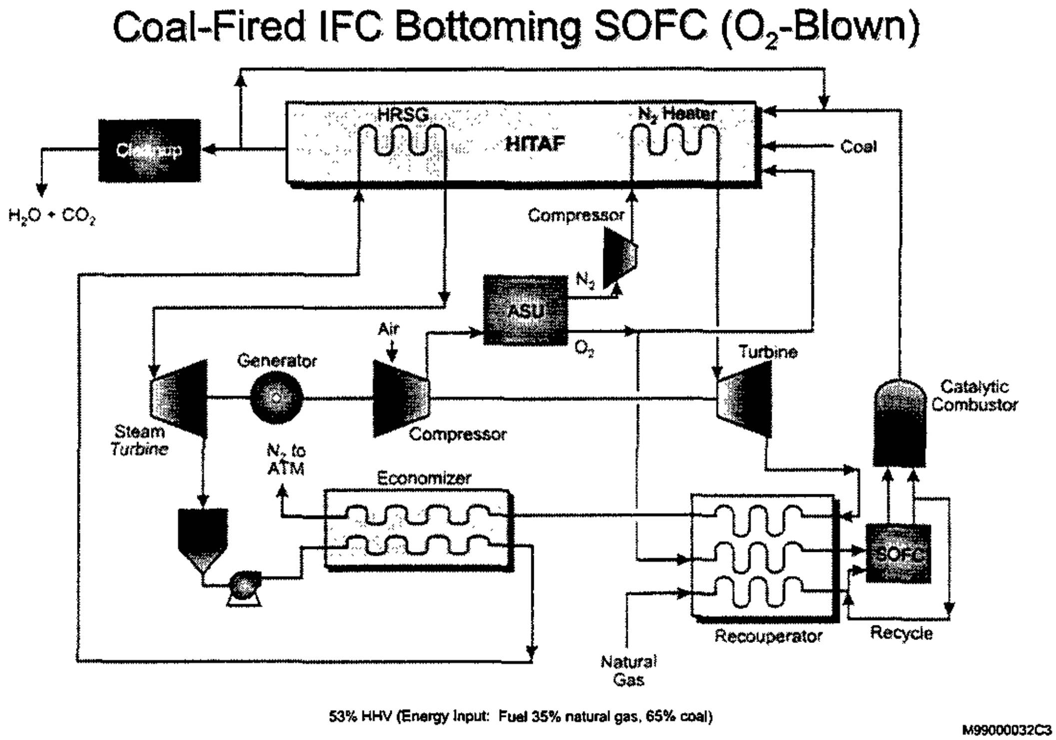

Figure 5. Combustion-Based Vision 21 System With CO_2 Separation

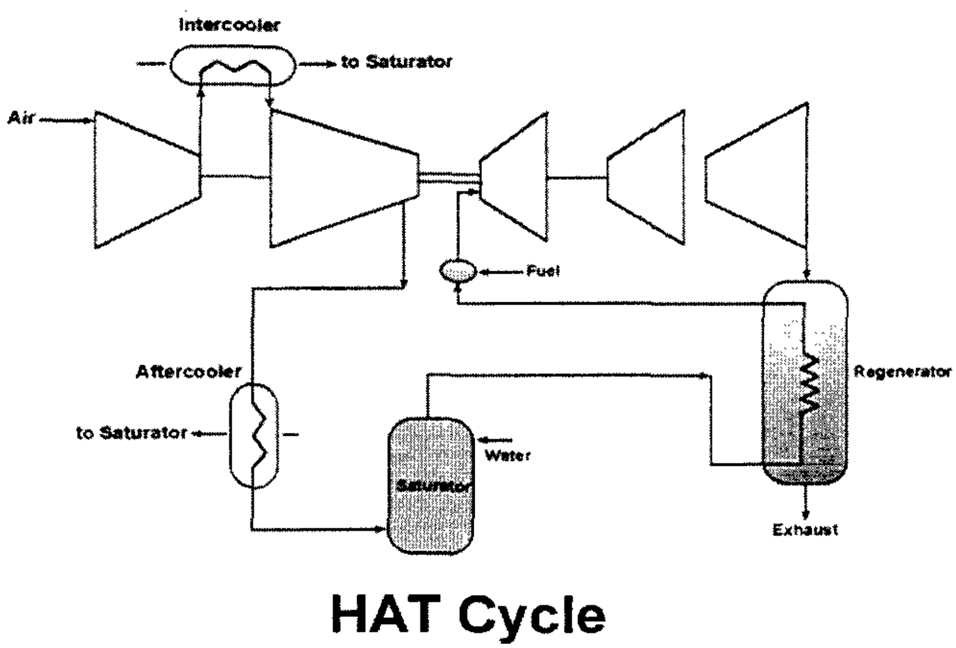

Figure 6. Humid Air Turbine Cycle

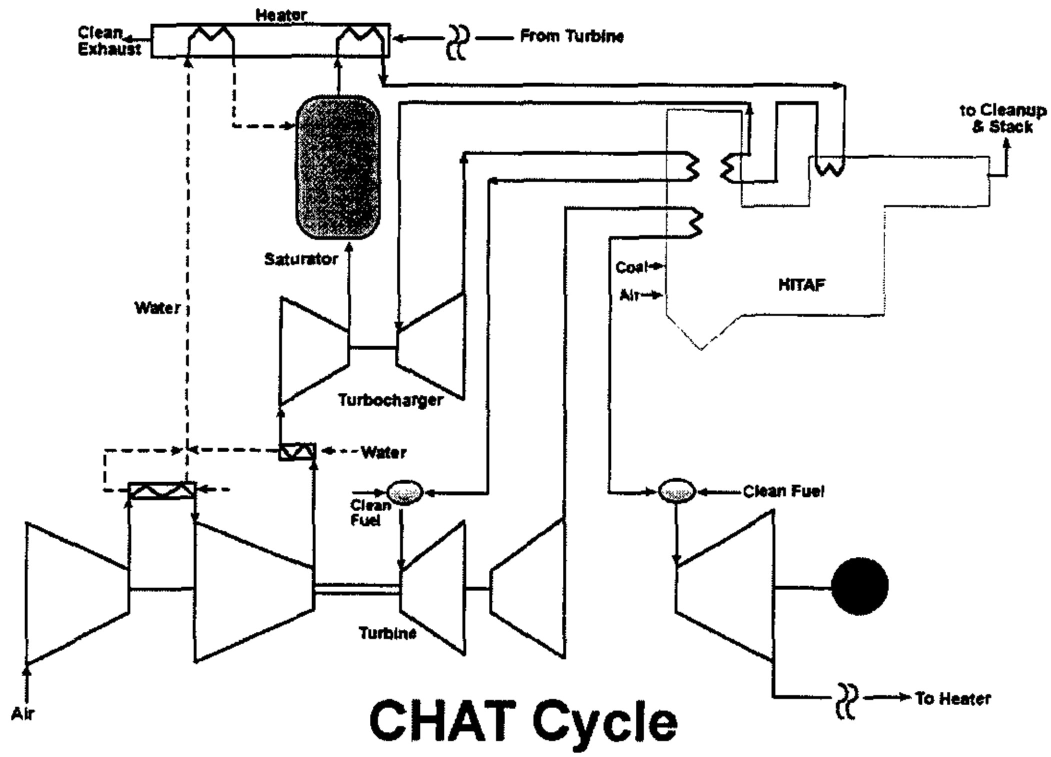

Figure 7. Cascaded Humid Air Turbine Cycle

CO_2 SEQUESTRATION: OPPORTUNITIES AND CHALLENGES

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ABSTRACT

Carbon management and sequestration offers an opportunity for reducing greenhouse gas emissions that can complement the current strategies of improving energy efficiency and increasing the use of non-fossil energy resources. Furthermore, this approach will enable us to continue to enjoy the benefits of fossil fuels while protecting our climate. When most people think of sequestering carbon, they think of planting trees. However, the focus of this paper is the capture of CO_2 from large stationary sources and then reusing it or sequestering it in geologic formations or the deep ocean.

The two biggest challenges for carbon sequestration from large stationary sources are reducing costs associated with CO_2 separation and capture and developing sinks that are safe, effective, and economical. In this paper, we present results of a detailed analysis of costs associated with today's technology for CO_2 separation and capture followed by a discussion of opportunities to lower costs in the future. Then, we review the challenges involved in developing secure storage reservoirs.

I. INTRODUCTION

Fossil fuels currently supply over 85% of the world's energy needs and will remain in abundant supply well into the 21st century. They have been a major contributor to the high standard of living enjoyed by the industrialized world. We have learned how to extract energy from fossil fuels in environmentally friendly ways, controlling the emissions of NO_x, SO_2, unburned hydrocarbons, and particulates. Even with these added pollution controls, the cost of fossil energy generated power keeps falling. Despite this good news about fossil energy, its future is clouded because of the environmental and economic threat posed by possible climate change, commonly referred to as the "greenhouse effect". The major anthropogenic greenhouse gas is carbon dioxide (CO_2) and the major source of anthropogenic CO_2 is combustion of fossil fuels. However, if we can develop technology to capture and sequester the fossil fuel CO_2 in a cost-effective and environmentally sound manner, we will be able to enjoy the benefits of fossil fuel use throughout the next century.

The idea of capturing CO_2 from the flue gas of power plants did not start with concern about the greenhouse effect. Rather, it gained attention as a possible economic source of CO_2, especially for use in enhanced oil recovery (EOR) operations where CO_2 is injected into oil reservoirs to increase the mobility of the oil and, therefore, the productivity of the reservoir. Several commercial CO_2 capture plants were constructed in the late 1970s and early 1980s in the US (Arnold *et al.*, 1982; Hopson, 1985; Kaplan, 1982; Pauley *et al.*, 1984). The North American Chemical Plant in Trona, CA, which uses this process to produce CO_2 for carbonation of brine, started operation in 1978 and is still operating today. However, when the price of oil dropped in the mid-1980s, the recovered CO_2 was too expensive for EOR operations and all of the other CO_2 capture plants were closed. Several more CO_2 capture plants were subsequently built (Barchas and Davis, 1992; Sander and Mariz, 1992) to take advantage of some of the economic incentives in the Public Utility Regulatory Policies Act (PURPA) of 1978 for "qualifying facilities" and to provide CO_2 for sale commercially.

In addition to power plants, there are a number of large CO_2-emitting industrial sources that could also be considered for application of capture and sequestration technologies. In natural gas operations, CO_2 is generated as a by-product. In general, gas fields may contain up to 20% (by volume) CO_2, most of which must be removed to produce pipeline quality gas. Therefore, sequestration of CO_2 from natural gas operations is a logical first step in applying CO_2 capture technology. In the future, similar opportunities for CO_2 sequestration may exist in the production of hydrogen-rich fuels (e.g., hydrogen or methanol) from carbon-rich feedstocks (e.g., natural gas, coal, or biomass). Specifically, such fuels could be used in low-temperature fuel cells for transport or for combined heat and power. Relatively pure CO_2 would result as a byproduct (Socolow 1997).

The first commercial CO_2 capture and sequestration facility started-up in September 1996, when Statoil of Norway began storing CO_2 from the Sleipner West gas field into a sandstone aquifer 1000 m beneath the North Sea. The CO_2 is injected from a floating rig at a rate of 20,000 tonnes/week (corresponding to the rate of CO_2 produced from a 140 MW_e coal fired power plant). The economic incentive for this project is the Norwegian carbon tax of \$50 per tonne CO_2. Costs of the operation are approximately \$15/tonne of CO_2 avoided (Olav Kaarstad, Statoil, personal communication). An international research effort is being organized to monitor and document this effort so the experience can be built on by future endeavors.

To date, all commercial plants to capture CO_2 from power plant flue gas use processes based on chemical absorption with a monoethanolamine (MEA) solvent. MEA was developed over 60 years ago as a general, non-selective solvent to remove acid gases, such as CO_2 and H_2S, from natural gas streams. The process was modified to incorporate inhibitors to resist solvent degradation and equipment corrosion when applied to CO_2 capture from flue gas. Also, the solvent strength was kept relatively low, resulting in large equipment sizes and high regeneration energy requirements (Leci, 1997). Therefore, CO_2 capture processes have required significant amounts of energy, which reduces the power plant's net power output. For example, the output of a 500 MW_e (net) coal-fired power plant may be reduced to 400 MW_e (net) after CO_2 capture. This imposes an "energy penalty" of 20% (i.e., (500-400)/500). The energy penalty has a major effect on the overall costs. Table 1 shows typical energy penalties associated with CO_2 capture -- both as the technology exists today and as it is projected to evolve in the next 10-20 years.

Table 1. Typical Energy Penalties Associated with CO_2 Capture

Power Plant Type	**Today**	**Future**
Conventional Coal (PC)	27 - 37% (Herzog and Drake, 1993)	15% (Mimura *et al.*, 1997)
Gas (NGCC)	15 - 24% (Herzog and Drake, 1993)	10 - 11% (Mimura *et al.*, 1997)
Advanced Coal (IGCC)	13 - 17% (Herzog and Drake, 1993)	9% (Herzog and Drake, 1993)

II. CO_2 CAPTURE

Methodology for Analysis of Economic Studies

We have conducted a comparison of published studies from the past several years that analyzed the economics of capturing CO_2 from fossil fuel-fired power plants. These studies fall into three categories:

- Advanced Coal based on Integrated Gasification Combined Cycle (IGCC) power plants. In these plants, the coal is gasified to produce syngas (hydrogen plus carbon monoxide). The syngas is cleaned and shifted (carbon monoxide reacts with steam to form hydrogen and CO_2), followed by the removal of CO_2 with a physical absorbtion process (e.g., Selexol or Rectisol). The hydrogen rich gas left behind is used to fuel a combined cycle power plant.

- Conventional Coal based on Pulverized Coal (PC) power plants. In these plants, steam is raised in a boiler to drive a steam turbine. The CO_2 is removed from the flue gas with an MEA scrubbing process.

- Natural Gas is based on Natural Gas Combined Cycle (NGCC) power plants. In these plants, the natural gas drives a gas turbine. Steam to drive a steam turbine is produced by recovering heat from the gas turbine exhaust, as well as some additional natural gas firing. The CO_2 is removed from the flue gases with an MEA scrubbing process.

All studies were made using commercially available technology and include the cost of compressing the captured CO_2 to about 2000 psia for pipeline transportation. The studies analyzed in our work are listed below.

IGCC Studies:

Argonne National Laboratory (Doctor *et al.*, 1996; Doctor *et al.*, 1997)
Politecnico di Milano, Italy (Chiesa *et al.*, 1998)
SFA Pacific (Simbeck, 1998)
University Of Utrecht, Netherlands (Hendriks, 1994)
EPRI (Condorelli *et al.*, 1991; Booras and Smelser, 1991)

PC Studies:

University Of Utrecht, Netherlands (Hendriks, 1994)
EPRI (Smelser *et al.*, 1991; Booras and Smelser, 1991)
SFA Pacific (Simbeck, 1998)

NGCC Studies:

SFA Pacific (Simbeck, 1998)
Norwegian Institute of Technology (Bolland and Saether, 1992)

We analyzed two cases from each study, a power plant with no capture (reference plant) and the same plant with CO_2 capture. Where necessary, we adjusted the fuel feed rates so that they were the same for both cases of a study. This means that the net power output for the capture plant will be less than the reference plant due to the energy requirements of the capture process (see Figure 1). It is also important to point out the difference between the amount of CO_2 captured and the amount avoided. In the example from Figure 1, we capture 242 tonnes CO_2/hr (0.769 kg/kWh), but avoid only 184 tonnes CO_2/hr (0.586 kg/kWh). The difference is caused by the need for energy in the capture process, which produces additional CO_2. This additional CO_2 must be subtracted from the CO_2 captured to obtain the CO_2 avoided.

From each study, we extracted the following data for both the reference and capture cases:

- Cost of electricity (¢/kWh) broken down into capital, fuel, and operation and maintenance (O&M)
- Capital cost ($/kW)
- Net power output (MW)
- CO_2 emitted (kg/kWh)
- Heat rate (Btu/kWh) defined on a low heating value (LHV) basis (note that the thermal efficiency is simply 3412 Btu/kWh divided by the heat rate)

In addition, we extracted the following data so that we could put each of the studies on a common economic basis:

- the annual capacity factor (defined as operating hours per year divided by 8760, where 8760 is the total number of hours in a year).

- the cost of fuel in $ per million Btu based on fuel LHV.

- the capital charge rate. The capital charge rate can be roughly correlated to the cost of capital and is used to annualize the capital investment of the plant. Specifically, the capital component of the cost of electricity ($/kWh) equals the capital charge rate (fraction/yr) times the capital cost ($/kW) divided by the hours per year of operation.

We adjusted each study to the following economic basis:

- Capital charge rate of 15%/yr
- Annual capacity factor of 0.75 (6570 hrs/yr)
- Fuel costs for gas of $2.93 per million Btus based on LHV
- Fuel cost for coal of $1.24 per million Btus based on LHV

The studies all reported their results in U.S. dollars, but used different year dollars in their calculations. It should be noted that, despite inflation, electricity production costs have been falling. We decided not to adjust for different year dollars since the precision that might be gained in converting these estimates to the same year dollars is small relative to the uncertainty inherent in and across these cost estimates.

The key results calculated were the energy penalty and the cost of capture. The capture costs can be represented in many ways, but we have found the most useful representations to be the mitigation cost ($/tonne CO_2 avoided) and the incremental cost of electricity (¢/kWh). Both of these metrics have their strengths and weaknesses.

The mitigation cost is a useful way to compare different mitigation strategies. This becomes important if we move toward a trading system, as it gives us a way to compare projects based on very different technologies. For example, using this metric, we can compare the cost of a sequestration project directly to the cost of an energy efficiency project or a renewable energy project. As a cautionary note, the mitigation cost is very sensitive to the basis chosen (see Figure 6 and accompanying discussion).

The incremental cost is important because it is a direct measure of the effect of CO_2 mitigation on electricity prices. This becomes extremely important for developers of new power projects considering the use of sequestration. Because this number is not normalized by the amount of CO_2 mitigated, it may be misleading. Specifically, this cost is the product of the unit cost of mitigation times the quantity mitigated. Therefore, two different strategies may yield similar incremental cost of sequestration, but one may sequester a large quantity at a small unit cost, while the other may sequester only a small amount at a large unit cost.

The incremental cost may be broken down into two components, the capture cost and the derating cost. The capture cost is defined as the increase in electricity costs due to the additional capital and O&M required for CO_2 capture. It is normalized with the net power output of the reference plant. The derating cost is the increase in the cost of electricity due to the energy requirement of the capture process that results in a derating of the net power output for a given fuel input. With our definition, note that costs associated with both the reference plant and the capture process are derated.

In addition to the above studies, we included very recent data from the Coal Utilization Research Council (CURC, 1998) for all three types of plants. This data was limited to the reference plants.

Results of Analysis of Economic Studies

The results of our data extraction and calculations are shown in Figures 2-4.

Figure 5 plots the cost of electricity versus CO_2 emissions for each of the analyzed studies. In terms of emissions, the plants cluster into three groups: reference coal plants at about 0.75 kg CO_2 per kWh, reference natural gas plants at about 0.35 kg CO_2 per kWh, and the capture plants at about 0.1 kg CO_2 per kWh. If we ignore the EPRI results (this is the oldest study and was based on very conservative assumptions), we can make the following observations about costs:

- NGCC reference plants are 3-4 ¢/kWh
- Coal reference plants are 4-5 ¢/kWh, with PC plants slightly less expensive than IGCC plants
- NGCC capture plants are 5-6 ¢/kWh
- IGCC capture plants are 6-7 ¢/kWh
- PC capture plants are 7-8 ¢/kWh

Today, PC plants are slightly less expensive than IGCC plants. However, if CO_2 emissions are regulated and carbon sequestration becomes necessary, IGCC plants will become more economical. Also, with current technology, coal is at a competitive disadvantage compared to natural gas for both reference and capture plants.

We can make the following observations on the incremental cost of electricity (once again, ignoring the EPRI studies):

- For IGCC plants, the range is 1.1 to 1.7 ¢/kWh
- For NGCC plants, the range is 1.9 to 2.1 ¢/kWh
- For PC plants, the range is 2.3 to 3.1 ¢/kWh

This suggests that if CO_2 emissions from power plants were regulated, IGCC plants could be most efficient in meeting the goals through a sequestration pathway. This would require the reference IGCC plant to become more competitive with the NGCC reference plant.

In order to understand how to derive the mitigation cost, Figure 6 plots a subset of points from Figure 5. Specifically, the points plotted are from the SFA Pacific IGCC capture plant and all three CURC reference plants. The slope of the line connecting the 2 IGCC points is the cost of mitigation in \$/tonne of CO_2 avoided. Furthermore, by extending this line to the y-axis, we can read the cost of electricity that a zero emission technology (e.g., renewables) must beat to be competitive with the sequestration option. For this example, the cost is 64.8 mills/kWh.

It was noted earlier that the mitigation cost depends on the basis chosen. In the above example, the basis was an IGCC plant with no capture and the result was \$26/tonne CO_2 avoided. One can argue that PC plants are the standard coal plant today, so that should be the basis. This yields a mitigation cost of \$29/tonne CO_2 avoided. If one took as the basis an NGCC plant (this is the most popular plant being built today), the mitigation cost would be \$107/tonne CO_2 avoided.

Figure 7 plots the mitigation cost for each of the studies analyzed versus the energy penalty. In each instance, the basis of the mitigation cost was chosen to be the corresponding reference plant from each study. To find the total mitigation cost, the sequestration cost (i.e., the cost of transporting and injecting the CO_2 into the ground or ocean) must be added to the numbers shown in Figure 7. Preliminary estimates are that an additional \$5-10 per tonne CO_2 avoided will be needed.

Lowering the Cost of Capture

The results presented above represent technology that is commercial today, but that has not been optimized for CO_2 capture and sequestration. One should not judge the viability of CO_2 capture power plants based on today's relatively expensive technology. There is great potential for technological improvements that can significantly lower costs. Improving the thermal efficiency of the reference plants, reducing the energy penalty for CO_2 capture (see Table 1), or improved separation technologies can significantly reduce costs. Even larger costs reductions are possible in the future with new innovative technologies. For example, it may be possible to develop new types of power plants and power cycles.

The paper documents only a first step in our analysis of capture costs. We plan to develop a model based on the results presented above to conduct sensitivity studies. Some variables we will study include: reference plant heat rates, energy penalty and derating costs, capital costs of the capture plant, and fuel costs.

III. CO_2 SEQUESTRATION

Once the CO_2 is separated and captured, the next challenge is what to do with the large quantities of CO_2. Commercial use of the CO_2 would improve the economics of sequestration, but large-scale applications are limited. Most chemical processes that use CO_2 require relatively small amounts, with totals on the order of millions of tons, not the billions of tons produced from fossil fuels. However, geological formations and the deep ocean have the potential to store the large quantities produced by fossil fuel combustion (see Table 2).

Sequestration in Geological Formations

Geological sinks for CO_2 include deep saline formations, depleted oil and gas reservoirs, and unmineable coal seams. These formations are widely dispersed around the world and together can hold hundreds to thousands of GtC. In addition, the technology to inject CO_2 into the ground is well established. Injection of CO_2 into geological formations for enhanced oil recovery (EOR) is a mature technology. In 1998, a total of about 60 million m^3/day (about 43 million metric tons per year) of CO_2 was injected at 67 commercial EOR projects. As mentioned in the Introduction of this paper, geological sequestration solely for reasons related to climate change is currently being demonstrated in the North Sea in Norway.

Table 2. Order of magnitude estimates for the worldwide capacity of the various sinks. Note that the worldwide total anthropogenic carbon emissions are about 7 GtC per year.

Sequestration Option	**Worldwide capacity in GtC**
Ocean	1000s
Deep Saline Formations	100s to 1000s
Oil and Gas Reservoirs	100s
Unmineable Coal Seams	10s to 100s
Terrestrial Biosphere	10s to 100s
Utilization	0.1 per year

Oil and gas reservoirs appear to be a promising geologic storage option because these reservoirs have already demonstrated their ability to contain pressurized fluids for long periods of time. Currently abandoned oil and gas reservoirs in the US could hold about 3 billion tonnes of CO_2, while the ultimate reserves of oil and gas would hold roughly 100 billion tonnes of CO_2 (Winter and Bergman, 1996). If CO_2 is injected into active oil reservoirs, the added benefit of EOR could offset some of the sequestration costs.

Deep (>800 m) saline formations that are hydraulically separated from shallower aquifers and surface water supplies may be the best long-term geologic storage option because their potential storage capacity is large (1000s of GtC) and they are widely distributed. Because there has been less interest in them compared to oil and gas formations, the properties of deep saline formations are not as well known, which leads to technical uncertainty. It is believed that the formation should be located under a relatively impermeable cap, yet there should be high permeability, as well as porosity, below the cap to allow the CO_2 to be distributed efficiently. Effects of gravity segregation and fingering may limit the effective storage, and fractures and open peripheries can allow leakage (Lindeberg, 1997). Experience can be gleaned from the disposal of industrial wastes as the US currently uses over 400 wells to inject about 75 million cubic meters of industrial waste (some hazardous; some non-hazardous) into deep aquifers each year (Bergman and Winter, 1996).

Sequestration in saline formations or in oil and gas reservoirs is achieved by a combination of three mechanisms: displacement of the *in-situ* fluids by the CO_2, dissolution of the CO_2 into the fluids, and chemical reaction of the CO_2 with minerals present in the formation to form stable, solid compounds like carbonates. Displacement dominates initially, but dissolution and reaction become more important over time scales of decades and centuries.

Abandoned and uneconomic coal seams are another potential storage site. CO_2 diffuses through the pore structure of the coal, where it physically adsorbed to the coal. This process is similar to the way in which activated carbon removes impurities from air or water. CO_2 can also be used to enhance the recovery of coal bed methane (Gunter *et al.,* 1997). Estimated US coal bed methane resources are large -- ranging from 275 to 649 trillion cubic feet, with current production coming mainly from the San Juan Basin in SW Colorado and the Black Warrior basin in Alabama (Dawson, 1995). Although still in the development stage, the process has been tested in pilot scale field studies conducted by Amoco and Meridian in the San Juan Basin.

Several steps need to be implemented to further the development of geologic sequestration of CO_2. The main issues are uncertainties in the volumes available for storage, the long-term integrity of the storage, and the costs associated with CO_2 transport to the sequestration site and the storage operation itself. Storage integrity is important not only to prevent the unintended return of CO_2 to the atmosphere, but also for concerns about public safety and the potential liability should there be a release. However, much experience resides in the oil and gas industry to prevent accidental releases.

Sequestration in the Deep Ocean

The ocean represents the largest potential sink for anthropogenic CO_2. It already contains an estimated 40,000 GtC (billion tonnes of carbon) compared with only 750 GtC in the atmosphere and 2,200 GtC in the terrestrial biosphere (IPCC, 1996). As a result, the amount of carbon that would cause a doubling of the atmospheric concentration would change the ocean concentration by less than 2%.

Worldwide anthropogenic emissions of carbon to the atmosphere are about 7 GtC. The ocean-atmosphere flux is about 90 GtC per year, with a net ocean uptake of 2 ± 0.8 GtC (IPCC, 1996). On a time-scale of a thousand years, over 90% of today's anthropogenic emissions of CO_2 will be transferred to the ocean. Discharging CO_2 directly to the ocean would accelerate this ongoing, but slow, natural process and would reduce both peak atmospheric CO_2 concentrations and their rate of increase.

In order to better understand the opportunities and challenges involved in direct injection of CO_2 into the ocean, a simplified view of the ocean and the properties of CO_2 are presented here. The exact temperature and density profiles in the ocean vary with season and location. In general, the vertical profile of the oceans are characterized by three strata: an upper mixed layer about 100 m deep, a thermocline region extending to about a depth of 1000 m, and a deep region. The upper mixed layer features near-constant density and temperature profiles over the depth and gaseous concentration levels in equilibrium with the atmosphere. The thermocline is stably stratified by large temperature and density gradients that inhibit vertical mixing. The deep ocean has near-constant temperatures in the range of 2-5°C. Pressure at any depth can be approximated by assuming a 1 bar pressure rise for every 10 m of depth.

At typical pressures and temperatures that exist in the ocean, pure CO_2 would be a gas above approximately 500 m and a liquid below that depth. In seawater, the liquid would be positively buoyant (i.e., it will rise) down to about 3000 m, but negatively buoyant (i.e., it will sink) below that depth. At about 3700 m, the liquid becomes negatively buoyant compared to seawater saturated with CO_2. In seawater-CO_2 systems, CO_2 hydrate ($CO_2 \cdot nH_2O$, $6<n<8$) can form below about 500 m depth depending on the relative compositions. CO_2 hydrate is a solid with a density about 10% greater than that of seawater.

In the near-term, a consensus is developing that the best strategy is to discharge the CO_2 below the thermocline at depths of 1000 - 1500 m. The technology exists today to implement such a strategy. The injection can be achieved with minimal environmental impacts. The cost is low compared to most other ocean injection strategies and is much smaller than anticipated capture costs. The major question revolves around sequestration efficiency.

To implement the above strategy, two methods of injection have been proposed. One is to transport the liquid CO_2 from shore in a pipeline and discharge it from a manifold lying on the ocean bottom, forming a rising droplet plume about 100 m high (Liro *et al.*, 1992). Alternatively, the liquid CO_2 could be transported by tanker and then discharged from a pipe towed by the moving ship (Ozaki *et al.*, 1995). Although the means of delivery are different, the plumes resulting from these two options would be quite similar and, therefore, research on these two injection methods should be considered complementary.

Another approach to CO_2 ocean sequestration is to inject the CO_2 as deeply as possible in order to maximize the sequestration efficiency. In order to accomplish this, new technology would need to be developed, with unknown costs. One such idea is to inject the liquid CO_2 to a sea floor depression forming a "deep hydrate lake" at a depth of about 4000 m (Ohsumi, 1995).

In assessing strategies for implementing ocean sequestration of CO_2, several key research topics need to be addressed:

- **Sequestration efficiency**, which is very site-specific, refers to how long the CO_2 will remain in the ocean before ultimately equilibrating with the atmosphere. The use of ocean general circulation models are required to determine sequestration efficiencies.

- **Environmental impacts** must be viewed at two different scales. *On a global scale*, direct injection of CO_2 to the ocean can be considered environmentally beneficial compared to our present trajectory. *On a local scale*, the most significant environmental impact is derived from lowered pH as a result of the reaction of CO_2 with seawater (Magnesen and Wahl, 1993; Kollek, 1993; Auerbach *et al.*, 1997). Impacts would occur principally to non-swimming marine organisms (e.g., zooplankton, bacteria and benthos) residing at depths of about 1000 m or greater and their magnitude will depend on both the level of pH change and the duration of exposure (Auerbach *et al.*, 1997). However, available data suggest that impacts associated with pH change can be completely avoided if the injection is properly designed to disperse the CO_2 as it dissolves (Caulfield *et al.*, 1997).

- **Engineering analysis,** in terms of what technology exists and what must be developed, is an important consideration. Led in part by the oil industry, great strides have been made in undersea off-shore technology.

IV. CONCLUDING REMARKS

Carbon management and sequestration presents an opportunity for us to address climate change concerns while still enjoying the benefits of fossil fuels. However, there are several challenges that must be met.

One challenge is to reduce the cost of sequestration associated with separation and capture of CO_2 from power plants. Of the three types of power plants studied, advanced coal plants like IGCC had the lowest incremental cost of electricity for CO_2 capture. This suggests that coal could compete with natural gas in a greenhouse gas constrained world.

Another challenge is to verify the feasibility of the various geologic and ocean reservoirs for CO_2 storage. This includes understanding the long-term fate of the CO_2 and addressing environmental and safety concerns.

Finally, carbon sequestration should be viewed as part of an overall strategy that includes improved efficiency and non-carbon energy sources. For us to be able to address climate change issues at a reasonable cost, we will need as many mitigation options as possible.

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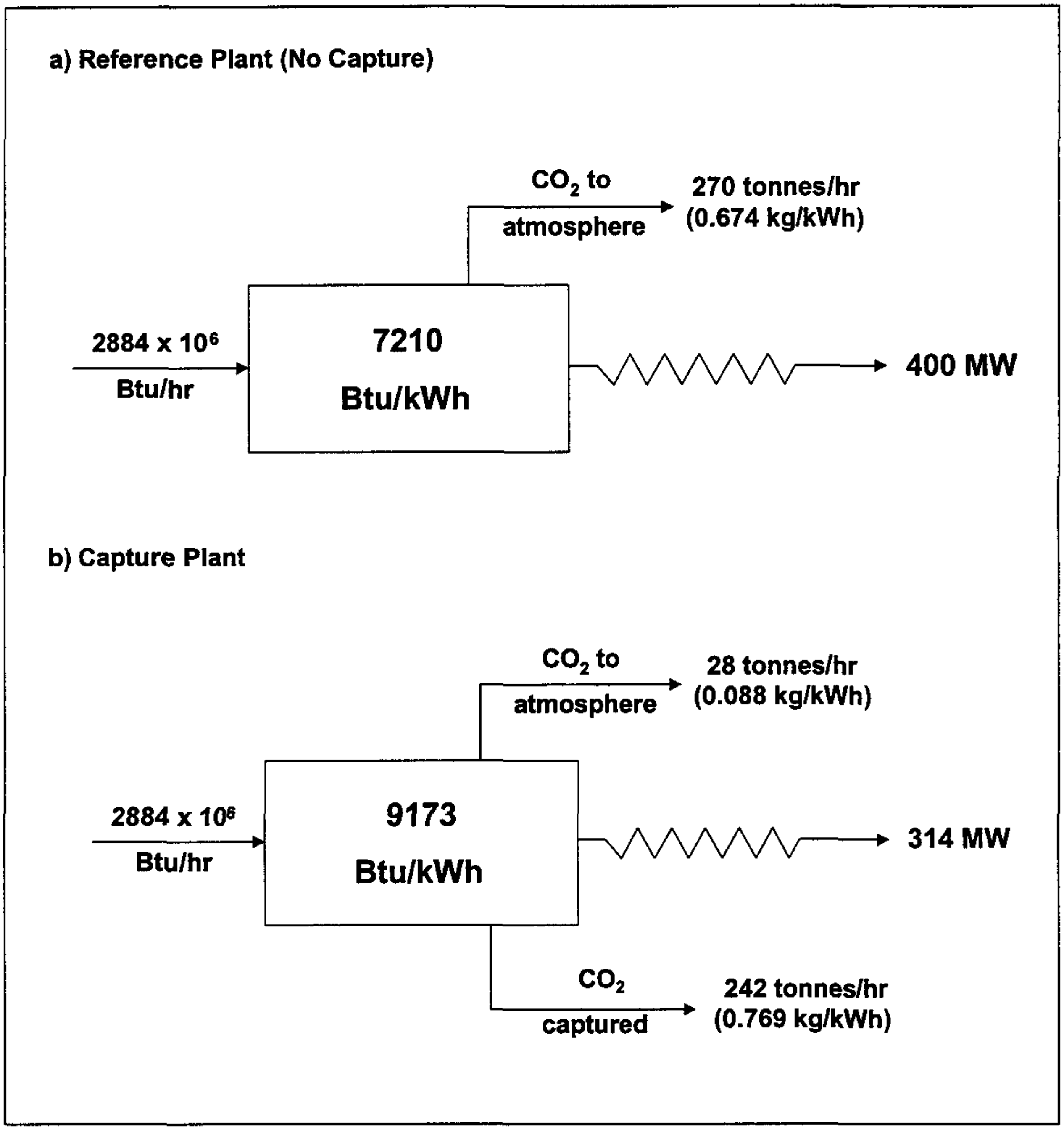

Figure 1. Example based on SFA Pacific IGCC Study (Simbeck, 1998). We adjusted the capture plant to have the same energy input as the reference plant. The energy penalty is 21.5% [(400-314)/400]. While we capture 242 tonnes of CO_2/hr, we only avoid 184 tonnes/hr. This is calculated by comparing the 0.088 kg/kWh emitted from the capture plant to the 0.674 kg/kWh emitted by the reference plant. We multiply the difference by 314 MW to obtain the 184 tonnes of CO_2/hr avoided.

Study:		Argonne	Milan	SFA Pacific	Utrecht	EPRI	CURC
Cycle:		IGCC	IGCC	IGCC	IGCC	IGCC	IGCC
Data Description	Units	Value	Value	Value	Value	Value	Value
Reference Plant							
coe: CAPITAL	mill / kWh	30.4	35.1	29.7	28.9	36.5	29.7
coe: FUEL	mill / kWh	11.0	9.2	8.9	9.7	11.5	10.1
coe: O&M	mill / kWh	9.3	7.1	7.9	6.5	10.4	6.1
Capital Cost	\$/kW	1332	1536	1300	1265	1600	1300
Net Power Output	MW	413.5	404.1	400.0	600.0	431.6	
CO_2 emitted	kg/kWh	0.790	0.709	0.674	0.760	0.868	0.740
Thermal Efficiency (LHV)		38.4%	46.0%	47.3%	43.6%	36.8%	42.0%
Heat Rate (LHV)	Btu/kWh	8888	7425	7210	7826	9280	8124
Cost of Electricity	¢/kWh	5.07	5.13	4.65	4.50	5.85	4.58
CO_2 Capture Plant							
coe: CAPITAL	mill / kWh	38.5	43.7	40.3	41.1	49.1	
coe: FUEL	mill / kWh	12.1	10.8	11.4	11.7	14.3	
coe: O&M	mill / kWh	11.2	8.7	10.8	9.4	18.8	
Capital Cost	\$/kW	1687	1913	1767	1799	2152	
Net Power Output	MW	377.5	345.6	314.4	500.0	347.4	
CO_2 emitted	kg/kWh	0.176	0.071	0.088	0.040	0.105	
Thermal Efficiency (LHV)		35.0%	39.3%	37.2%	36.3%	29.6%	
Heat Rate (LHV)	Btu/kWh	9735	8684	9173	9399	11528	
Cost of Electricity	¢/kWh	6.18	6.32	6.25	6.21	8.23	
Comparison							
Capture Cost	¢/kWh	0.57	0.27	0.26	0.67	0.77	
Derating Cost	¢/kWh	0.54	0.91	1.34	1.04	1.60	
Incremental coe	¢/kWh	1.10	1.18	1.59	1.71	2.38	
Energy Penalty		8.7%	14.5%	21.4%	16.7%	19.5%	
\$/tonne CO_2 avoided	\$/tonne	\$18	\$19	\$27	\$24	\$31	
Basis							
Capital Charge Rate		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Yearly Operating Hrs	hrs/yr	6570	6570	6570	6570	6570	6570
Fuel Cost, LHV	\$/MMBtu	1.24	1.24	1.24	1.24	1.24	1.24

Figure 2. Results of data analysis for IGCC plants. Note that the studies have been adjusted to a common economic basis.

Study:		Utrecht	EPRI	SFA Pacific	CURC
Cycle:		PC	PC	PC	PC
Data Description	Units	Value	Value	Value	Value
Reference Plant					
coe: CAPITAL	mill / kWh	26.3	25.8	29.7	26.3
coe: FUEL	mill / kWh	10.3	11.7	9.5	10.5
coe: O&M	mill / kWh	5.9	10.3	7.9	5.8
Capital Cost	$/kW	1150	1129	1300	1150
Net Power Output	MW	600	513.3	400.0	
CO_2 emitted	kg/kWh	0.800	0.909	0.717	0.771
Thermal Efficiency (LHV)		41.0%	36.1%	44.4%	40.3%
Heat Rate (LHV)	Btu/kWh	8322	9440	7680	8462
Cost of Electricity	¢/kWh	4.25	4.78	4.71	4.25
CO_2 Capture Plant					
coe: CAPITAL	mill / kWh	47.3	56.7	46.2	
coe: FUEL	mill / kWh	13.4	17.8	11.3	
coe: O&M	mill / kWh	12.9	29.9	12.3	
Capital Cost	$/kW	2073	2484	2022	
Net Power Output	MW	462	338.1	336.5	
CO_2 emitted	kg/kWh	0.100	0.138	0.128	
Thermal Efficiency (LHV)		31.5%	23.8%	37.4%	
Heat Rate (LHV)	Btu/kWh	10832	14331	9130	
Cost of Electricity	¢/kWh	7.37	10.44	6.98	
Comparison					
Capture Cost	¢/kWh	1.42	2.10	1.16	
Derating Cost	¢/kWh	1.69	3.56	1.11	
Incremental coe	¢/kWh	3.12	5.66	2.27	
Energy Penalty		23.0%	34.1%	15.9%	
$/tonne CO_2 avoided	$/tonne	$45	$73	$39	
Basis					
Capital Charge Rate		15.0%	15.0%	15.0%	15.0%
Yearly Operating Hours	hrs/yr	6570	6570	6570	6570
Fuel (Coal) Cost, LHV	$/MMBtu	1.24	1.24	1.24	1.24

Figure 3. Results of data analysis for PC plants. Note that the studies have been adjusted to a common economic basis.

Study:		SFA Pacific	Trondheim	CURC
Cycle:		NGCC	NGCC	NGCC
Data Description	Units	Value	Value	Value
Reference Plant				
coe: CAPITAL	mill / kWh	11.1	17.2	12.0
coe: FUEL	mill / kWh	16.7	19.2	18.5
coe: O&M	mill / kWh	3.0	2.7	2.4
Capital Cost	$/kW	485	754	525
Net Power Output	MW	400.0	721.2	
CO_2 emitted	kg/kWh	0.330	0.400	0.366
Thermal Efficiency (LHV)		60.0%	52.2%	54.1%
Heat Rate (LHV)	Btu/kWh	5688	6536	6308
Cost of Electricity	¢/kWh	3.07	3.91	3.28
CO_2 Capture Plant				
coe: CAPITAL	mill / kWh	25.9	30.1	
coe: FUEL	mill / kWh	18.8	22.5	
coe: O&M	mill / kWh	6.9	5.2	
Capital Cost	$/kW	1135	1317	
Net Power Output	MW	353.7	615.3	
CO_2 emitted	kg/kWh	0.056	0.046	
Thermal Efficiency (LHV)		53.0%	44.5%	
Heat Rate (LHV)	Btu/kWh	6433	7667	
Cost of Electricity	¢/kWh	5.17	5.77	
Comparison				
Capture Cost	¢/kWh	1.50	1.02	
Derating Cost	¢/kWh	0.60	0.85	
Incremental coe	¢/kWh	2.10	1.86	
Energy Penalty		11.6%	14.7%	
$/tonne CO_2 avoided	$/tonne	$77	$53	
Basis				
Capital Charge Rate		15.0%	15.0%	15.0%
Yearly Operating Hours	hrs/yr	6570	6570	6570
Fuel (NG) Cost, LHV	$/MMBtu	2.93	2.93	2.93

Figure 4. Results of data analysis for NGCC plants. Note that the studies have been adjusted to a common economic basis.

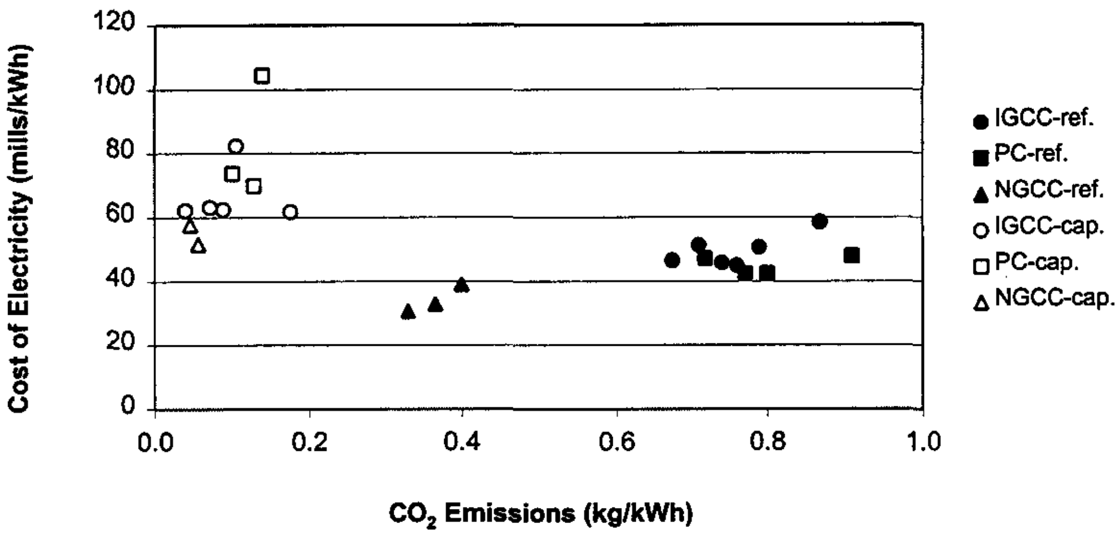

Figure 5. Cost of Electricity versus CO_2 Emissions for the 13 reference plants and the 10 capture plants analyzed.

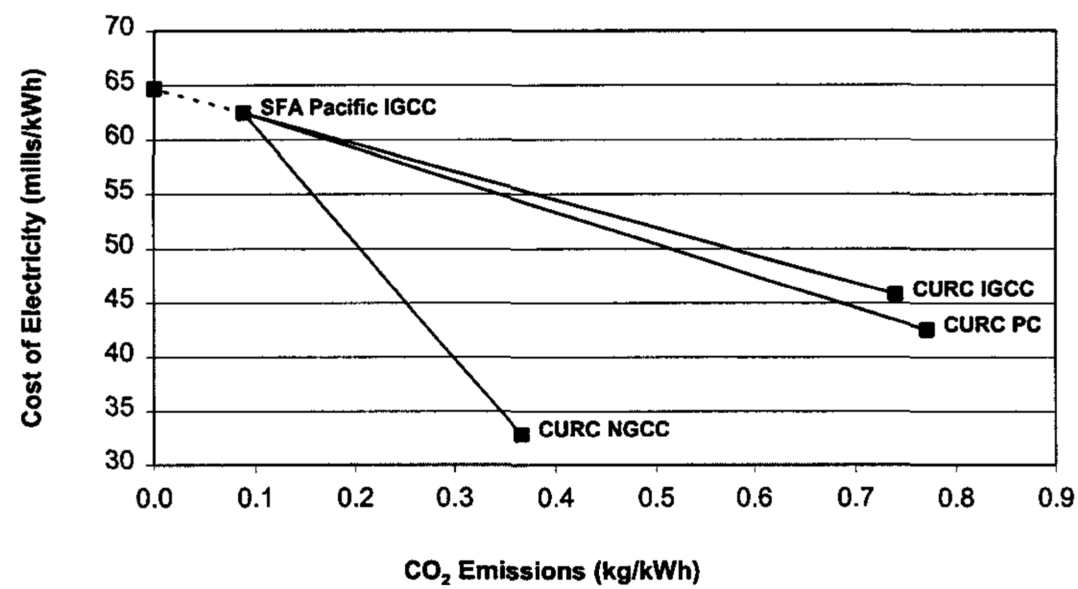

Figure 6. Calculation of Mitigation Costs. Mitigation cost is simply the slope of the connecting line. All reference plants are based on the CURC data. The cost of mitigation varies depending on the reference plant chosen for the base case: IGCC ($26/tonne CO_2 avoided), PC ($29/tonne CO_2 avoided) and NGCC ($107/tonne CO_2 avoided). Target cost of electricity for a zero emission technology is y-intercept of each line (e.g., 64.80 mills/kWh for IGCC base.)

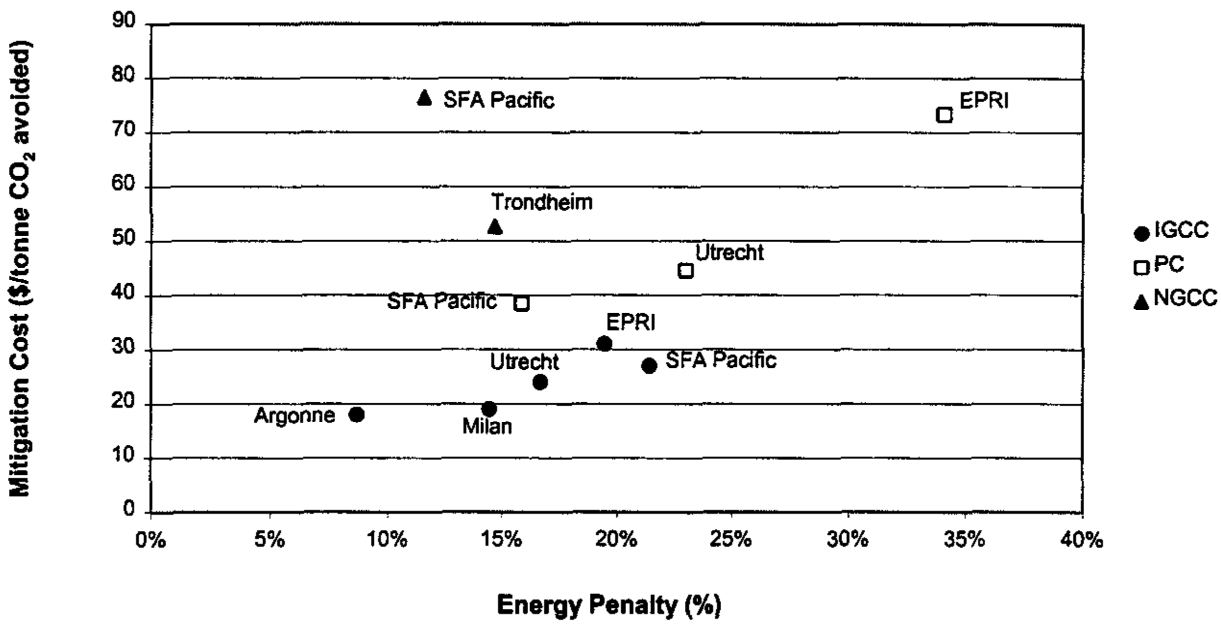

Figure 7. Summary of mitigation costs for the 10 studies analyzed, plotted against the energy penalty. Note that the basis of the mitigation cost is the corresponding reference plant from each individual study.

CLEAN FOSSIL ENERGY TECHNOLGIES

The Future of Clean Fossil Technologies
in a Deregulated Environment

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The R&D Paradox

"Either it won't work, or it's not needed."*

Insight obtained by the author in Chinese fortune cookie shortly after beginning career in energy R&D.

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What Drives the Value of Energy Businesses Today?

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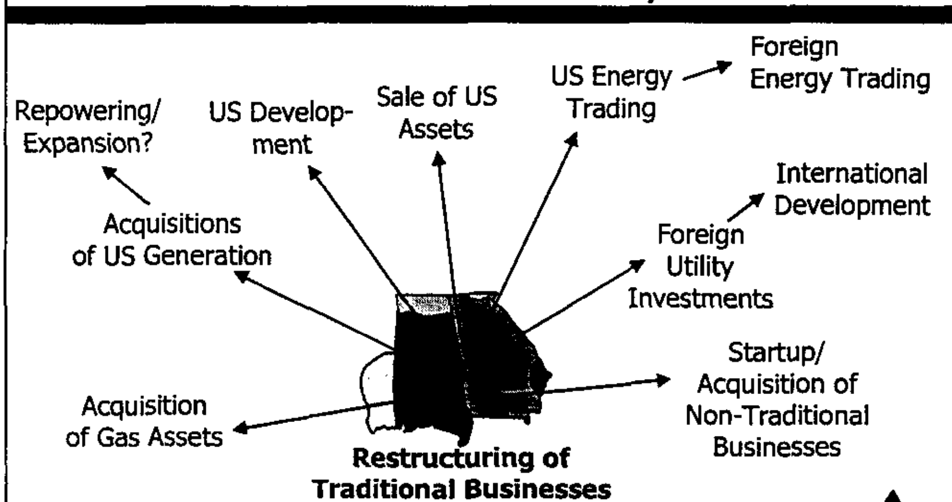
What Drives the Value of Energy Businesses Today?



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What Drives the Value of Energy Businesses Today?

- Superior Financial Restructuring of the Company
- Redeployment of Capital
- Superior M&A Execution and Integration
- Superior Trading and Risk Management
- Minimize Business Unit Surprises
- Positive Regulatory Relations
- Organic Growth of Regional Operations
- Capitalize on Selective Greenfield Development Opportunities

NOTE ABSENCE OF R&D and TECHNOLOGY!

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- Positive Regulatory Relations
- Organic Growth of Regional Operations
- Capitalize on Selective Greenfield Development Opportunities

NOTE ABSENCE OF R&D, TECHNOLOGY!

The Energy R&D Challenge

- Corporate growth and value generation are not in new technologies today
- Not a lot of support, funding, management attention on development of new fossil generating technology …
- Difficult to find a research sponsor (with money!) in today's energy company

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What New Business Perspectives Are Needed?

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Important Trends

- Development of Trading and Marketing Perspective
  - New "breed" of decision-makers
  - Relatively short time horizon
  - "Mark-to-Market" Accounting Perspective
  - Emphasis on "EBITDA" and "Value at Risk" Rather Than Return on Equity
  - The "Options Analysis" Perspective

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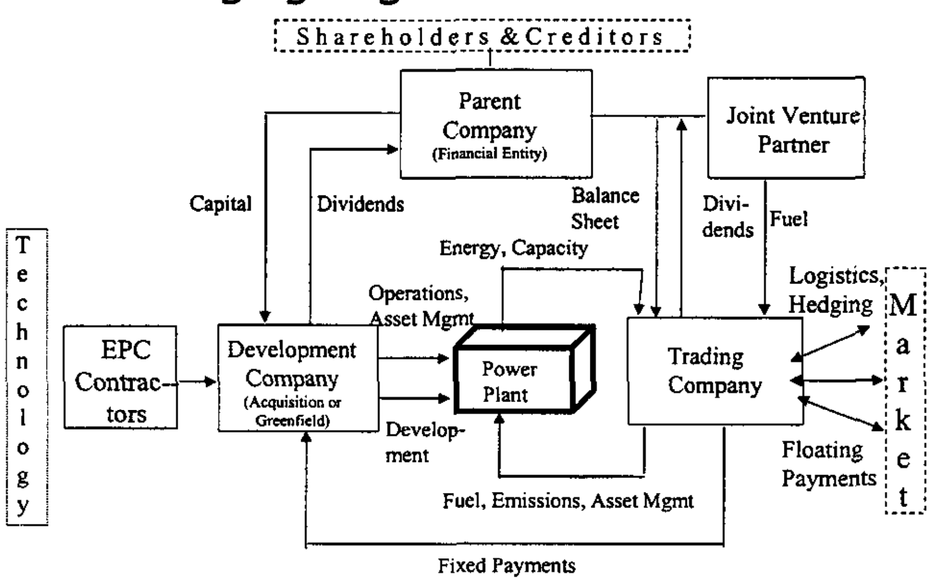
Changing Organizational Structure



New Breed of Decision-Makers

- "Energy trading and marketing" function is where much of the risk and return of generating assets will be managed in successful energy companies
- Traders take on market price risk for Btu's and MWh's
- Traders must hedge underlying power and fuel price risk as well as market price volatility
- Trading company will become the most exposed to underlying shifts in price structures (e.g., natural gas supply constraints, CO_2 legislation)

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Who Are The Traders?

- They may not wear suits (or socks!)
- They may have never seen a power plant before (let alone coal!)
- They may have MBA's or PhD's in mathematics (or both!)
- They may not associate "volatility" with coal specs
- They may make more money than the CEO

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Trading Viewpoint Is Different

- Traders think in primarily financial and commodity market terms:
  - Long or short power, gas, etc.
  - Call and put options for power, gas, etc.
  - Daily mark-to-market accounting to measure "value at risk"
  - Traders view generating assets as "real options"

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Short Time Horizon

- Trading time horizons are relatively short due to:
  - Risk associated with long-dated positions
  - Organizational focus on annual EBITDA compared to Value at Risk
  - Limited trading liquidity beyond near-term
    - Continued low energy prices, relatively low price volatiliy *over long term*
- Longest liquid trading horizon is 5 years, with positions up to 10 years

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End of Short-Term Speculation: The Forward Curve

- Energy trading companies are inherently "risk averse"
  - Value at Risk methodology requires balancing of long and short positions
    - Derivatives can result in very high leverage
  - High short-term volatilities in fuels and power
  - Limitations of risk capital
- Trading tends to center around the "forward curve"
  - Not "speculation" -- can transact today at forward prices

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"Mark-To-Market" Accounting Perspective

- Overall position of trading company is revalued on at least daily basis
  - Value based on change in market prices, volatilities, etc.
  - Can produce fatal changes in P&L due to market price movements
  - Trading rules typically require adjustment of positions, up to liquidation, to maintain risk target
  - Distinguish between P&L and cashflow!
- Mark-to-Market encourages focus on short-term, continuing search for new value, frequent changes in positions and strategies, etc.
- Options have real value whether exercised or not

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"The Market Is The Market"

- Take your cue from the forward curve
- Expect coal to become a traded commodity
- Watch for cross-commodity correlations
- Utilize mark-to-market accounting concepts to track your performance
- Market should tell you the value of flexibility

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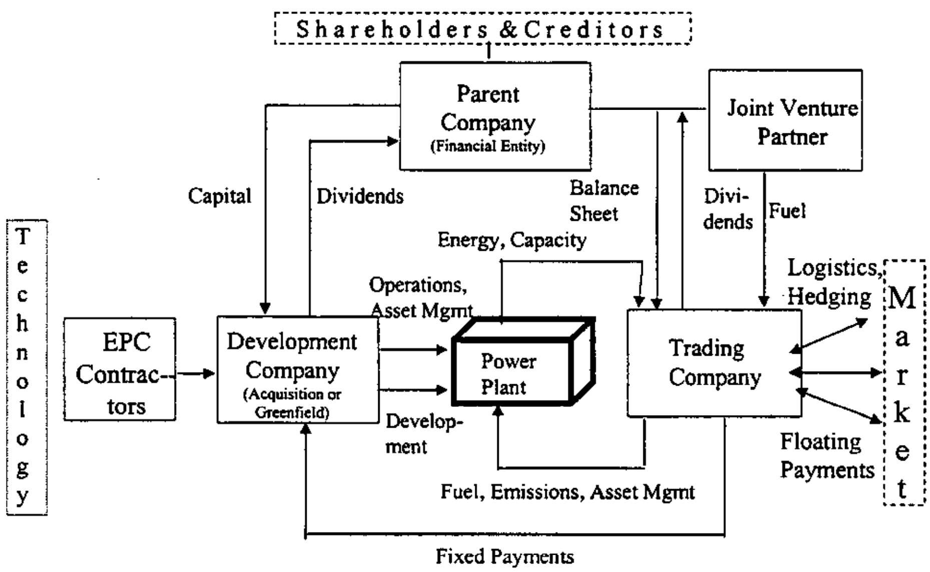
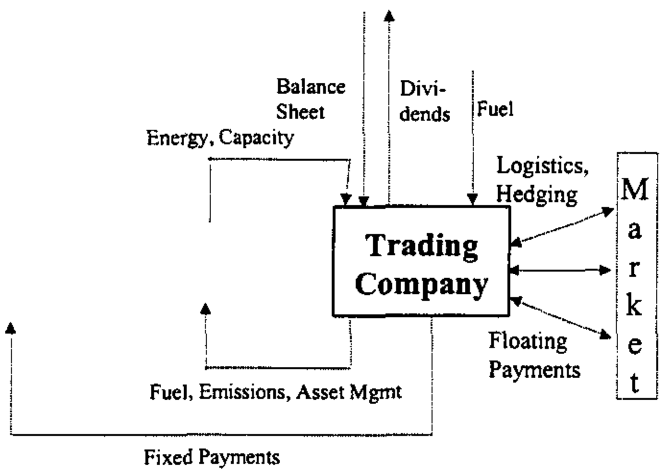
Where Is Value at Risk for Generating Assets?



Where Is Value at Risk for Generating Assets?



Application of a "Real Options" Approach to Energy R&D

"Real Options:" A Decision-Making Revolution*

- Growing use of options analysis for corporate decision-making
  - **Enron**: Installation of gas turbine peakers
  - **HP**: Analysis of shipping products pre-assembled vs. partially assembled (flexibility to respond)
  - **Cadence Design Systems**: Define "optionality" when negotiating chip contracts
  - **Airbus Industrie**: Quantify and define value of optional purchases in aircraft contracts
  - **Anadarko Petroleum**: Analyze value of uncertain outcomes in bidding for oil leases

*Business Week, June 7, 1999

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Energy R&D as "Real Options"

- R&D Investments, technologies are "real options"
  - Investment today can generate the possibility of new opportunities tomorrow

- Clean non-gas fossil fuel technologies are options which can hedge against price risk, price volatility

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The Future Is Not Static

- Traded markets look for correlations and arbitrage them
  - Newsprint and Uncoated Papers
- The best forecast will be wrong.
- The future will be affected by what energy technologist do now based on their *predictions* of the future
  - Similar to Heisenberg's Uncertainty Principle
- Traders focus on the *forward curve*

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Traditional View of the Future

- Increasing demand will cause gas prices to rise rapidly and continuously
  - Markets don't generally allow gaps; "Price cures price"
    - E.g.: At a given \$/MWh, how much power is interruptible? (power shock of Jun '98)
- Coal is so plentiful it will always be cheap.
  - The fact that it's so cheap says that the market believes it's not the CHEAPEST option today ...
  - When coal is a near substitute for natural gas, its price will rise
  - As energy markets deregulate, coal becomes traded, coal will also rise in price volatility

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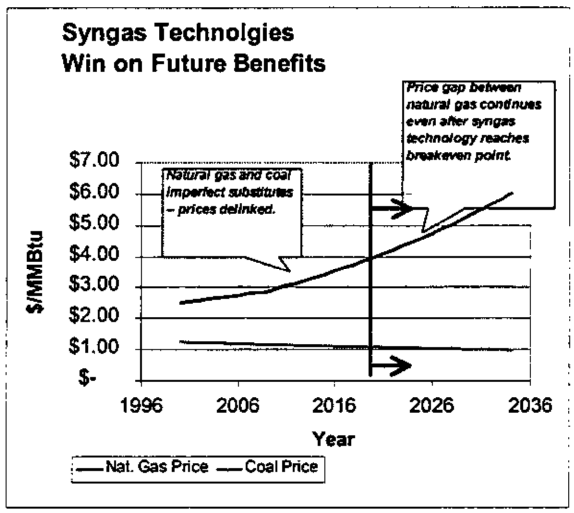
Basis of Traditional Gas vs. Coal Evaluation - Cost Approach



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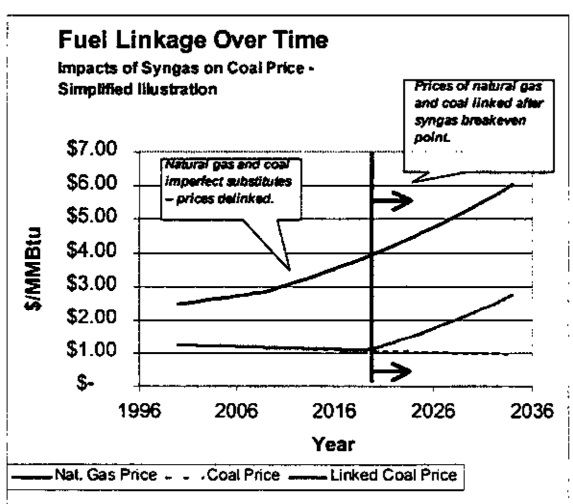
Natural Gas and Coal Prices Linked by Syngas Technology - Price Approach



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Market May Prefer "Low" Technology Vs. High Tech

- Real options analysis may tell you that the added investment for high technology is not worth it
  - Subject to continuous reassessment
- Definition of "high tech" must address options variables
  - High tech baseload technology has lower option value due to operating constraints (e.g., combined cycle)
  - Low tech peaking technology has high option value due to operating *flexibility*

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Why Traders Like Gas Turbines

- Low option premium
- Reasonable "liquidity" (implementation, equipment, fuel supply, etc.)
- Short lead time for implementation
- Quick on and off operation -- higher optionality
- Good range of energy "strike prices" (heat rates
- Readily hedgable fuel input
- Surrogate for long-dated options
- Inherent flexibility -- multifuel capability, convertibility, options on options (compound options), etc.
- ~~Meaningful certainty as a hedge~~

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How Does the Market Value Today's Syngas Technology?

– What is the value of a syngas "cap" for a 300 MW natural gas power plant?

Plant Capacity, MW	300
Today's Nat. Gas Price, $/MMBtu	$2.50
Est. Nat. Gas Volatility	30 %
Syngas Price (1st Year)	$4.00
Syngas Call Option - Term, yrs	5
1st-Year Syngas Option Value	$7 mm
10-Year Syngas Option Value	$124 mm
10-Year Option value, $/MMBtu	$9.07

Note

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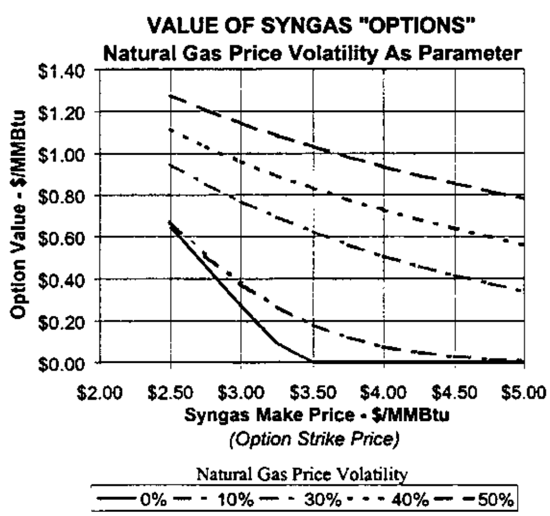
Importance of Price Volatility



SOME OBSERVATIONS:

- **Think of "Option Value" as contribution to fixed cost of syngas plant**
- **"In-the-Money" syngas option is not worth much if natural gas volatility is low**
- **"Out-of-the-Money" syngas option can be very valuable if natural gas volatility is high**

Note: Natural gas at $2.50/MMBtu

Option Value of Syngas Plant
Some Observations ...

- A plant that could produce syngas from coal (or other low-cost fuel) at an "out-of-the-money" price of $4.00/mmBtu ...
  - Theoretically has a value ***today*** as a hedge against natural gas exposure
    - *Indicative values might be $350 to $500/kWe based on selling forward 10 years*
    - *Indicative value possibly $500 to $750/kWe based on selling forward 15 years*
  - Its value depends not only on relative fuel ***prices*** but on fuel price ***volatility***

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Some Observations ...

- Note that "low-tech" syngas plant should have substantial option value *today*, even though it can't deliver gas near market price
- For "out-of-the-money" syngas price, the option value should be compared to the capital cost of building the facility:
  - Can a syngas plant be built for $500-700/kWe today?
- Ability to realize option value depends on liquid market for long-dated options

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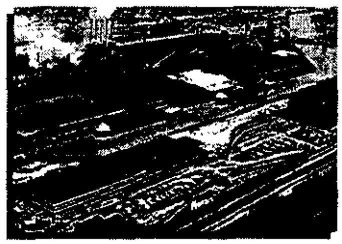
The Dream of River Rouge

Question: Does fully integrated "energy complex" have better payoff than low-tech syngas plant?

Minerals



Automobiles

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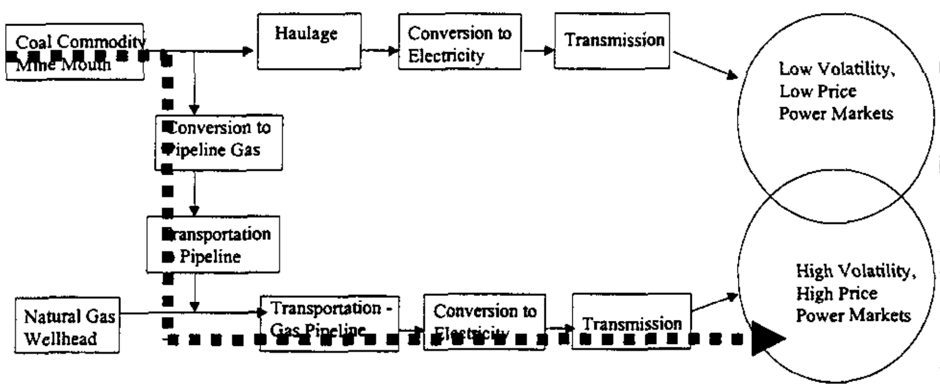
Integrated vs. Nonintegrated Consider the "Price Chain"



***Challenge:* Could pipeline syngas technology have better payoff than IGCC if it competes in high price markets, minimizes siting costs?**

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"Enabling Technologies" -- A Real Options View

- R&D programs often define enabling technologies along process, engineering lines
- Key "enabling technologies" from a real options perspective:
  - Allow rapid deployment of technology (engineering, construction)
  - Allow wide deployment in any location (scale, water consumption, etc.)
  - Allow deployment of "integrated" systems one module at a time (convert into a series of compound options)

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- Flexibility
- Rapid deployment

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"Real Options" Analysis of R&D Value

- Options approach can be used to help assess the value of R&D
- Question -
  - Given the price characteristics of the natural gas and coal markets, how is the option value improved by reducing cost of coal syngas by R&D efforts?

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Concluding Remarks

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A Parting View on Energy Technology

- Innovations in energy technology WILL play a vital role in the 21st Century
- Many vested interests (utilities, IPP's, marketers, owners of fuel reserves, consumers, etc.) WILL NOT spend money for Vision 21 programs as structured
- Most clean fossil technologies under development are viewed as second-string, underfunded, uneconomic, unappealing
  - *As a potential customer, I don't know how to justify investment in current programs*

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Which Future Are You Planning For?

- Have you considered ...
  - Changes in settlement patterns (urban densification) -- where will you put your integrated factories?
  - Sunk costs -- existing generation, transportation, infrastructure will probably be used!
  - Coal will become a traded commodity! (take on volatility of power and nat. gas

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Will "Traders" Support Energy R&D?

- Traders will soon be in the best position to value your R&D products!
- However -- not likely to invest in programs, demonstrations, basic research
- May have appetite to purchase "options" which can be used to hedge price and volatility risk
- Challenge: Developing a Market

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What is Your Product?

Try this product definition:

Making a market in "real options" for hydrocarbon-based fuels and feedstocks.

$

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What is Your Product?

Try this product definition:

Making a market in "real options" for hydrocarbon-based fuels and feedstocks.

?

What Is the Value of Your Product?

- Value and price your product properly, using the correct market economics
  - What does the market tell you about the value of your product?
- Check the forward curve -- what does it tell you about R&D?

"I've put the sweat of my life into this thing I have my reputation rolled up in it. And I have stated several times that if it is a failure, I'll probably leave this country and never come back, and I mean it."

Howard Hughes on the **Spruce Goose**

PANEL SESSION SUMMARY

Panel Session Summary
Issue 1: Deploying CCTs

7th Clean Coal Technology Conference
Knoxville, Tennessee
June 21-24, 1999

John M. Wootten
Vice President Environment & Technology
Peabody Group
St Louis, Missouri

Achieving Societal and Economic Goals

- The availability of diverse, reliable and affordable energy supplies has resulted in the achievement of societal and economic goals in developed countries
- Economic prosperity has led to environmental stewardship in the developed countries
- Developing countries are now seeking the same societal goals and economic prosperity
- Developing countries must also establish diverse, reliable and affordable energy supplies

Coal's Role in Achieving Societal and Economic Goals

- Coal is projected to continue to be a key component in the energy supplies of both developed and developing countries
- Current coal technologies can not satisfy the energy security and environmental goals of society and deliver affordable energy supplies
- The wide spread commercial deployment of CCTs will:
  - maintain a diverse fuel supply
  - maintain affordable energy supplies
  - achieve environmental goals

Institutional Barriers to Deploying CCTs

- PCAST 99 - no mechanism to move technologies from the demonstration phase to wide spread deployment
- "Buydown" Phase must address
  - financing of incremental costs
  - cost uncertainty
  - technology and other risk
- Need for public entity to provide policy and financial support

Financial Barriers to Deployment of CCTs

- CCT have higher efficiency than conventional PC but lower than natural gas combined cycle units
- CCTs capital costs should be 20% to 25% lower than PC, but 50% higher than NGCC
- IGCC and PFBC are competitive with PC but not NGCC in 2000, but could be competitive with NGCC in 2010 depending on the respective fuel prices
- The fuel price differential between coal and natural gas must be greater than $2.00/mmbtu for the CCTs to be competitive with NGCC

Developer Barriers to Deploying CCTs

- Capital risk twice that of NGCC
- Higher capital means higher taxes, insurance and financing costs
- Deregulation favors less capital intensive projects
- Construction schedules longer - slower response to market price signals for new capacity
- Start-up and shake down risks
- Revenue requirements dictate higher capacity factor
- Increased environmental law change exposure

Environmental Barriers to Deploying CCTs

- CCTs achieve high levels of control for conventional pollutants (particulate, SOx, NOx)
- CCTs have high levels of efficiency and reduced CO2 emissions but not as low as NGCC
- Carbon sequestration can achieve high levels of carbon control, but costs are currently prohibitive and much technological and other uncertainty exists
- Forest sequestration of carbon is the lowest cost option for existing plants
- Integrating technological sequestration with CCTs is a cost effective option if high levels of control are required

Incentives for Deploying CCT's

- Wide spread commercial application of CCTs will not occur without financial support for the developer to address the CCTs' increased technical and economic risk
- Incentives more acceptable than grants or subsidies
- Incentives must address
  - higher capital costs — investment tax credit
  - higher operating cost & risk — production tax credit
  - start-up risk — risk pool
- Qualifying technologies must demonstrate increased efficiency over time to qualify for support
- Program must be limited in scope and duration

Conclusions for Policy Makers

- Societal and economic goals can not be achieved or sustained without diverse, reliable and affordable energy
- Coal will continue to be a key component of the majority of countries energy supplies
- Deploying CCTs can enhance economic prosperity and environmental performance
- Financial incentives will be required to allow deployment in deregulated energy markets and in developing economies
- Incentives must address both the financial and technical risk for early commercial applications of CCTs

ISSUE 2: GLOBAL COMMUNITY RESPONSIBILITY-ROLE OF TECHNOLOGY AND PROJECT DEVELOPERS, FINANCIERS, AND CONSUMERS AND GOVERNMENTS

Robert Donovan
Program Manager
United States Energy Association
Washington, DC, USA

UNAVAILABLE AT TIME OF PRINTING

Summary of Issues Panel 3

Coal in Tomorrow's Energy Fleet:
Pressures and Possibilities

Coal in Tomorrow's Energy Fleet

- Session Chair Bob Bessette
- Stephen Gehl EPRI
- Lawrence A. Ruth DOE
- Howard Herzog MIT Energy Lab
- David Gallaspy Southern Energy, Inc

Steve Gehl

- Create a Roadmap to the Future that reflects the changing electricity industry
- Build a new Electricity Technology Road that the customer's needs define
- Will Central Generation role change? Perception Vs. Reality
- Investment Risks regarding Coal generation

Steve Gehl

- Sustainable growth is dependant on electricity
- World population and urban growth
- Decarbonization will continue
- Electricity expansion reduces primary energy loads

Steve Gehl

- World power plant capacity will triple
- $100-150 billion/year
- Less than what the world spends on cigarettes?
- Carbon intensity is and will continue to decline

Steve Gehl

- We can't do this with continued incremental technology applications:
- New technology needs to be discovered and developed

Steve Gehl

- Efficiency Gains
- Ever lower capital costs
- Gas and coal costs converge by 2020
- Cost effective CO2 Sequestration
- Don't eat clams, they may be the answer to saving coal from being Gored!

Steve Gehl

- Coal can account for 20% of world primary energy in 2050, requiring continued growth
- Broad-based, comprehensive research program is needed
- Emphasis must be on low cost, very high efficiency, high electrification, sequestration as a hedge against CO2 limits

Larry Ruth

- Vision 21 Advanced energy plants for the 21st Century
- Fossil fuel energy will continue to meet electricity and environmental needs through the next century.
- We must remove the environmental impacts

Larry Ruth

- The approach requires building on CCT and R&D programs that collaborate with industry and government
- High efficiency goals for coal and gas
- Near zero emissions, 40-50 % reductions of CO_2 compared to today's fleet
- Add sequestration for net zero CO_2 emissions

Larry Ruth

- Technology Module selections for technicians to choose
- Coal gasification with added processes gets us to the Vision 21 goal
- Requires flexible components/subsystems
- Multiple technologies
- Leapfrog improvements in costs/efficiencies

Larry Ruth

- Virtual Demonstration ability will need to be developed to simulate proposed power plant operations using new technologies and processes
- System integration of engineering, response, control and industrial ecology personnel (different people talking together)

Larry Ruth

- Displayed graphs of conceptual IGCC/Fuel Cell and combustion power plants
- Various audience reactions were evident!
- Co-production projects using various fuels and producing various beneficial products
- Japanese "Vision 21" IGCC/Fuel Cell plant currently being developed and tested

Larry Ruth

- Technology basis for Vision 21 plants
- Improved design and simulation tools
- Low cost electricity from fossil fuels
- Removal of environmental barriers
- Keeps U.S. the Leader in technology

Hal Herzog

- CO2 Sequestration: Opportunities and Challenges
- **<u>If CO2 reductions are needed</u>**
- More sustainable use of fossil fuels in a climate change regulatory environment
- Is it possible? Sequestration is one of several ways to address CO2 reductions

Hal Herzog

- Industrial processes
- Power Production
- Fuels decarbonization
- Segregation of CO2 is integral to sequestration

Hal Herzog

- Sleipner CO2 Injection - north sea
- Sink capacity - oceans, aquifers, wills, coal seams, terrestrial and utilization
- Soils contain two thirds of carbon sequestration

Hal Herzog

- Reduce costs
- Develop safe, effective and economic sinks
- Gain public acceptance
- How will enviro's define CCT and CO2 sequestration? Anti- renewables?

Hal Herzog

- Showed graph of plant CO2 capture technologies
- Explained energy penalties, costs and efficiencies of capture
- Cost of electricity vs.. CO2 emissions
- IGCC capture plant might produce less costly electrons than a NGCC capture plant!

Hal Herzog

- Calculation of mitigation costs - was beyond me! Appears expensive to remove CO2
- Appears CO2 removal from coal cheaper than from gas?
- www.fe.doe.gov/sequestration/
- web.mit.edu/energylab /www/hjherzog/

Dave Gallaspy

- The Future of Clean Fossil Technologies in a deregulated Environment
- "Either it won't work or it's not needed"
- Electric industry is in cultural evolution
- Deregulation changes risk, encourages spreading risk by expanding business interests but leaves R&D behind

Dave Gallaspy

- Power plant values are at risk and controlled by trading companies
- How do you get funding for R&D in this risky environment?
- Value at Risk vs.. Return on Equity
- New "breed" of decision-makers
- Gain understanding of "Mark to Market"

Dave Gallaspy

- Real options need analysis
- R&D is a "real option" to develop non-gas fossil fuel technologies which can hedge against price increases from gas generation
- Requires a different 'development model'
- High tech may not have as much option value as low tech

Dave Gallaspy

- The future is not static
- The best forecast may be wrong
- What energy technologists do now based on their predictions of the future is very important
- The coal vs. gas price relationship perception will change

Dave Gallaspy

- Low tech may be preferred as low risk , high value
- Price Volatility is very important
- Consistent syngas price, though higher per BTU is preferred over a low cost, but volatile natural gas priced Btu

Dave Gallaspy

- Integrated vs.. Nonintegrated technologies require 'price chain' analysis, especially when performing siting analysis
- Many vested interests will not invest in Vision 21 technologies as currently structured
- You need to define your market options!

Bob Bessette

- Did a great job as Chair of the Issues 3 panel!!

LUNCHEON

Moving Clean Coal Technologies From Demonstration to the Marketplace

MOVING CLEAN COAL TECHNOLOGIES FROM DEMONSTRATION TO THE MARKETPLACE

Kurt E. Yeager
President and CEO
Electric Power Research Institute
Palo Alto, California, USA

"The law of human acceleration", as the historian Henry James noted a century ago, "cannot be supposed to relax its energy to suit the convenience of man." That law of acceleration is hurtling us into a new century, a new millennium and a new age. The world James lived in contained fewer than two billion people. Today, we add nearly a billion every decade. The Industrial Revolution extended over generations and allowed time for human and institutional adjustment. Today's Information Revolution is far swifter, more concentrated and more drastic in its impact. Over the past century electricity has become the prime mover for that human acceleration.

For example, Edison is important to us not primarily because he invented the electric light—a commercial product—but because he invented the concept of electrification. The first electricity supply system was, in a sense, viewed as an engineering detail required to make light bulbs salable. Within a decade, however, electricity itself was the product, spawning the birth and development of today's power industry. But even this was not the result of greatest value. It was the incredible capability of electricity to improve every aspect of our lives and transform modern society. That was the unpredictable, intangible, yet immeasurably valuable outcome of Edison's innovation.

Coal has sustained a remarkably constant role as the dominant fuel source for U.S. power generation throughout the 20th century. Hydro, oil and gas, and nuclear have all been significant competition at different times but none has dislodged coal. The second major trend is the consistent growth in U.S. production and consumption of electricity. Since 1960, between 700 and 800 billion kilowatt-hours have been added each decade. Over this period, the fraction of U.S. energy consumption devoted to electricity has grown from about 25% to nearly 40%. The fundamental question is whether either, or both, of these robust trends will continue into the 21st century? My remarks today will focus on this question.

Today, technology for the power industry is changing at a more profound and faster pace than at any time since Edison's day at the dawn of commercial electrification. This, in turn is changing every aspect of the electricity enterprise. The change process is likely to accelerate as the opportunities for efficient conversion of energy to electricity more closer and closer to the customer; as power electronics usher in a new age of precision delivery system management; as information technology redefines the boundaries and relationships between producers and customers; and as new electrotechnologies leverage digital control and real-time communications, boosting both industrial and service sector productivity to new heights. All these innovations serve to increase the efficiency and precision advantages of electricity relative to other energy forms.

The broad outline of strategic implications of such a profound technical transformation can already be seen. Other industries already dealing with similar change provide us with some clues—e.g., telecommunications, airlines and banking.

- First, the customer is given choice and becomes king. New technology makes the customer, not the supplier, the new focus and controller of the business.

- Second, the business expands to emphasize value-added services to the customer, rather than just providing cost-plus commodities.

- Third, the distinction between previously parallel commodities becomes blurred as services merge. For example, electricity, telecommunications and natural gas are all becoming intertwined at the user's end as new service opportunities and creative providers emerge.

- Fourth, the existing industry infrastructure can become economically unstable and by-passable.

- Fifth, the historically well-defined and locally static, business becomes a globally expanding enterprise of new opportunities. The established functions—generation, transmission, and distribution—become only reference points from which to explore and exploit the new "white space" of business opportunity. This space is bounded more by entrepreneurial imagination and will power than by technological limitations.

Business in the 20th century was about muscle; in the 21st century, it will depend more on knowledge. In such an environment of change knowledge quickly gained and wisely used will be the differential among competitors.

In the context of the electric power industry, it is likely that these implications will place relentless pressure on the wholesale price of electricity, reflecting the relatively low cost of new natural gas-fired combustion turbines and most existing coal-fired plants. Generating capacity, which is unable to meet this pressure will be at increasing risk. Another related factor of note is the growing spot market for electricity as common carrier power delivery systems and retail competition expand. Both factors are reflected in the profound restructuring of the electric power industry now underway in response to technological change.

Over 85% of installed U.S. coal capacity today has production costs under 25 mills/kW. Yet the disparity between the highest and the lowest is more than 5-fold, implying that some of these plants, particularly those above the nominal competitive threshold of 20 mills/kWh, will be at increasing risk. But the situation is more dynamic than it appears. Technology can help to bring down operating costs across the board, possibly turning around some of these high-cost plants, and significantly reducing capital expenditures in the future—in short, technology can alter the entire competitive power generation profile. The top 20 plants in the U.S., for example, have production costs between 9 and 13 mills/kWh. The bottom line is that most of today's coal fleet will remain powerful competitors for the foreseeable future. Their competitive position will be further enhanced by the revolution occurring in power delivery that will enable them to serve more distant and lucrative markets.

Delivery is key to the opening up of true competition in electricity markets. Bulk power transfers have increased four-fold over the last decade, as fully 40% of the electricity generated in the U.S. is now sold on the wholesale market. Open access will only accelerate this trend. This poses an enormous challenge for a delivery system designed for a pre-competitive era.

Fortunately, a variety of advanced technologies, including power electronics, are becoming available that can help reduce the cost and improve the reliability of electricity, and bring the infrastructure into line with the requirements of a digital age. Power electronics, for example, affords electronic switching and control at utility voltages, turning the entire grid into the equivalent of a finely tuned circuit. These technologies provide an opportunity to fundamentally reshape power delivery, as deregulation creates a new, competitive power supply sector, allows transmission systems to serve as common carriers, and permits distribution systems to provide the foundation for the integration of multiple utility services.

For transmission systems, the advent of new technologies, ranging from power electronics to advanced communications, will facilitate competitive power markets by ultimately enabling the integration of the North American power grid under a single, continental control regime. Transmission lines will become the superhighways of electricity commerce, carrying low-cost power over longer distances to meet the needs of customers who now have electricity rates that might be twice as high as neighboring regions. The net result of advanced delivery technology and deregulation should be an enormous boost to utilities with low-cost, environmentally acceptable, coal fired power plants, many of which have considerable margin for greater base-load operation.

I would now like to move from the U.S. to a global perspective. Over the next two decades, the world, particularly Asia and Latin America, will be developing economically and structurally on an unprecedented scale, requiring prodigious amounts of energy and capital. By 2020, global energy needs are expected to grow by at least fifty percent, even as energy intensity (energy/$GDP) continues its long-term decline of about one percent per year. Contributing to the more efficient use of energy, global electricity consumption will more than double over the same period, effectively setting the foundation for economic development as these nations enter global competition.

Today, over 2 billion people in the world are without access to commercial energy in any form, contributing in part to one of the largest migrations in history, as people move from rural to urban areas in search of opportunity. By 2020 there will be more than 30 cities in the now less-developed world with populations greater than 10 million. These rapidly growing mega-cities will have significant problems meeting the infrastructure requirements of its new arrivals, ranging from electricity to sanitation to transportation. This underscores the reality that the greatest threat to the global environment is poverty and hopelessness. Typically their dominant energy form is not electricity but charcoal, wastes and kerosene. It is the resulting temperature of this human climate, and its implications for global security, which will inevitably occupy more of our attention as we enter the new century.

Looking at electricity needs, the level of per capita electricity consumption required as a springboard to even marginal achievement of economic progress beyond the subsistence level is about 1500 kWh/year. This represents, on average, at least a four-fold increase in electricity consumption for 60% of the world's population today. The result, however, would still represent less than 20% of the average per capita consumption in today's most advanced economic regions, specifically Western Europe, the United States, and Japan.

Coal will remain the primary fuel for electricity generation during this period of rapid infrastructure expansion. Particularly in the coal-rich countries of China and India, it is likely to account for at least 60% of primary energy primarily to meet electricity demand, which is growing in excess of 5% per year. Coal will also likely increase its share of total generation in the other countries of Asia, including Korea, Taiwan, Thailand, Indonesia and the Philippines, climbing to more than 35% in each case.

The persistent importance of coal is evident with no expected decline in the magnitude of its global utilization through at least mid-century. Natural gas, nuclear power and renewables all will grow in importance throughout this period but it is neither technologically nor economically feasible to expect that any one of these options will dominate the global energy economy. Global sustainability will require them all – tailored through persistent technical advances to most effectively meet local circumstances.

It is also important to recognize that our ability to modify energy trends on a global scale is a long-term endeavor in which the greatest global threat would result from constraining access to efficient energy, particularly in the developing regions of the world. This is evidenced by the 15-fold increase in global energy consumption this century and the need to nearly triple that availability again in the coming century. Just keeping future energy growth to this level will demand very significant improvements in the efficiency of energy use and, even more importantly, the ability to distribute it to those without meaningful access today. From this perspective, it is notable how modest the growth in carbon emissions will prove to be if we achieve the efficiency and related decarbonization improvements achievable through electrification.

This progress of primary energy substitution and efficiency improvement through technological innovation implies a steady continuation of energy decarbonization, leading in the new century to an energy system ultimately relying on electricity and hydrogen as complementary energy carriers. The result can be a global energy economy free of material emissions, leaving water as its primary by-product. The challenge is to most positively stimulate, not impede this progress.

This priority reflects the larger challenge of global sustainability. That is, the simultaneous, negotiated balancing of three forces—population expansion, economic aspirations and the conservation of natural resources. The threat of climate change through human-induced greenhouse gas emissions has undeniable political currency but it exists as a derivative of this larger challenge, which has been aptly coined the "grand trilemma". Resolving this trilemma has every prospect of becoming the defining issue of the 21st century.

Environmental progress depends on economic growth. In this strategic context, it is draconian to focus on short-term national carbon constraints at any cost. The cost and economic dislocation at both the national and global level associated with proposed range, at best symbolic, reductions are significant – at least $100/ton of carbon. It's no surprise that the only region of the world likely to meet this target is the Old Soviet Union, and it will do so in direct proportion to its economic decline.

In order to foster a more effective alternative, EPRI is joining a global coalition to develop a technology strategy for greenhouse gas control that will complement a "when and where" market-based approach to reductions. "When" allows for the timely turnover of capital stocks, and "where"allows for trading CO2 permits around the world, to achieve a least-cost approach. With trillions of dollars hanging in the balance, such an approach is essential to keep the global economy growing while improving environmental quality.

The greenhouse gas technology strategy as currently envisioned will be phased. The first phase will create a sensible near-term <u>hedging strategy</u> (one that by evaluating the various investment options and key uncertainties in a systematic way seeks to minimize the expected cost of complying with climate policy). The second phase will be a <u>transition strategy</u> to most efficiently use existing resources as a bridge to a reduced carbon economy. This strategy will in essence define a "carbon budget" to be allocated over time. The third phase will create an <u>adaptive strategy</u> that allows global society to take action now, and for future societies to be able to revise those strategies as uncertainties are resolved. Uncertainties today range from technology development to economic assessment to climate change science.

All of the above depends on relentless technical progress and innovation. Although U.S. private-sector R&D has, in the narrowest sense, become more cost-effective, its increasingly short-term focus has left a serious void in mid-range research programs that in the past have provided the source of much innovation. New realities are being shaped by rapidly growing international R&D capabilities which have crated both global options and competitive pressures whose dimensions are barely understood.

Faced with competing pressures for limited revenues, government is justifying its retreat from R&D on the presumption that a competitive private sector will pick up the slack. The assumption seems to be that every industry will react like the rapid, growth-oriented pharmaceutical and semi-conductor sectors. In reality, however, infrastructure industries simply don't have the same ability to rapidly create new or differentiated markets through R&D, or the opportunity to profitably apply the results outside the shared infrastructure. It is important that this difference be recognized in terms of incentives to offset the lower self-interest in R&D investment by infrastructure industries on which both our economy and environment depend.

The bottom-line for R&D and innovation is about building societal opportunities. This is a shared national imperative in which collaboration and competition not only coexist but reinforce each other. In fact, sophisticated competition depends on collaboration. Individual companies may compete fiercely in the marketplace to determine how markets are divided up, but collaborative R&D increases the size of the pie for everyone by creating new opportunities. We see that synergy over and over again in the most competitive industries, from semiconductors to photographic systems and advanced power storage devices, as well as the traditionally more collaborative infrastructure industries.

Conclusions

- Technology is changing at an unprecedented rate in all aspects of the electricity enterprise and is creating new forms and levels of competition. These innovations serve to underpin sustained growth in electricity relative to other energy forms both domestically and globally.

- Coal will remain an essential part of the electricity fuel portfolio on a global scale – if it embraces the technological opportunities available to improve its competitive cost and environmental performance. Equal priority should be given to sustaining coal as a resource and to adapting clean coal technology to meet the needs of the developing world where dependence on coal is essential for economic development.

- Technology is producing a steady decline in the carbon intensity of the world's energy economy. This robust trend has been sustained for over a century and has every promise of being continued through the coming century unless shortsighted energy and environmental policies interfere. For example, emphasis should be placed on collaborative actions that reflect enlightened self-interest, not rigid targets and timetables that both freeze technology and lead to unacceptable implementation costs.

- Continuing this decarbonization trend will therefore require space and time flexibility for innovative technology to effectively resolve the sustainability trilemma. Time is needed to develop new technology innovations and to apply them as capital stock is replaced. Location flexibility is needed to use these innovations where they will have the greatest benefit related to their cost, given the very large level of capital investment required. Failure to take this path can have severe consequences for U.S. productivity and global competitiveness, and deny a world at the margin of subsistance the means to participate in global economic development.

- Finally, progress depends on renewed incentives for investment in the R&D engine on which innovation depends, and in the energy infrastructure which must utilize the results. The incentives should be guided by a strategic roadmap for global energy progress, and should promote a sustained collaborative partnership between the public and private sectors. Only in this comprehensive way will the challenges facing energy in general, and coal in particular, be met.

The recent report of the President's Committee of Advisors on Science and Technology (PCAST) entitled Federal Energy R&D for the Challenges of the 21st Century sums up the situation well by concluding: "If the pace of scientific and technological progress is not sufficient, the future will be less prosperous economically, more afflicted environmentally, and more burdened with conflict than most people expect.

Thank you.

HOST RECEPTION

Remarks of U.S. Secretary of Energy
Bill Richardson

REMARKS OF
U.S. SECRETARY OF ENERGY BILL RICHARDSON
AT THE
7TH CLEAN COAL TECHNOLOGY CONFERENCE
KNOXVILLE, TENNESSEE
[Remarks Delivered in Kingsport, TN]
JUNE 23, 1999

When the Clean Coal Technology Program started up in the U.S. in the mid-1980s, the challenge was acid rain. It was an issue that affected regions of countries and, in some cases, bridged the boundaries of nations.

Emanating out from that challenge was a significant task -- "expand the menu of options" for reducing acid rain pollutants from coal – the chief recommendation of the U.S./Canadian Joint Envoys on Acid Rain. If this could be done, the Envoys said, (quote) "future policy decisions would become much easier."

It was quite a challenge, but as the Envoys believed, the rewards would be far sweeter. And so the Clean Coal pioneers – the people in this room took the challenge. In partnerships between the federal government, industry and state governments, you:

- Developed and demonstrated new ways to control pollutants at existing and new plants more reliably and at lower costs.
- You generated new ways to produce cleaner fuels that yielded more energy. And
- You created new ways to generate electricity, ways that departed from the traditional coal combustors and incorporated entirely new, more efficient and cleaner concepts.

In short, you developed and demonstrated an entirely new way of doing business. You have helped reshape coal's future.

You have invested heavily in clean coal technologies. We, as a nation, have also invested heavily in these technologies, as have many of our global neighbors. And that investment is paying off. There are 40 Clean Coal Technology programs in 18 states, from a Coal-burning Diesel in Alaska to Coal Gasification in Florida, and from Flue Gas Scrubbers in New York to Liquid Phase Methanol right here in Tennessee (Kingsport, to be specific). These are major projects, with a total value of nearly $6 billion dollars -- $4 billion from the private sector and states.

Each project – 24 which have completed their test runs -- is demonstrating first-of-its-kind technology. Let me give you a clear example of the kinds of results we're seeing.

In the 1980s, the technology to reduce nitrogen oxides cost almost $3,000 dollars for every ton of "NOx" reduced.

Today, because of research and development efforts and our Clean Coal Program, we have "NOx-reduction" technology that costs only $200 dollars per ton – a 15-fold reduction. One-half of the coal-burning plants in America are now equipped with this technology. Within the next year or so, that figure will be 3 out of 4.

We have more reliable and lower cost scrubbers. We have entirely new options for turning coal into a gas and using it to generate electricity in ways that achieve unprecedented levels of environmental cleanliness. These technologies are a preview of coal's future – and I wanted to come here this evening to tell you that, in my opinion, the future is as bright for coal as it is for any energy resource...if we continue our commitment to technology.

Coal remains a central mechanism in America's and the world's economic energy machines. It is safe to say that coal will continue to be the world's low-cost fuel of choice for decades to come. But we must also recognize that coal's full potential – in this country and globally – will be achieved only if the technology is developed to make coal an environmental fuel-of-choice.

I believe we have the tools to make that happen. I am here this evening to underscore our continued commitment to coal's future.

I wanted to bring that message to this group specifically because nowhere else will I find – in one room – a more concentrated collection of people who hold coal's future in their hands. I want you to leave this conference with a new mandate...a new commitment.

Today, we're looking at more stringent air regulations, and we are seeing more and more vividly the impact that greenhouse gases have on our environment. We have addressed the regional challenge of acid rain. Now, we're facing a challenge that is similar in concept, but far, far different in scope.

Today, the major challenge confronting coal – global climate change – knows no national boundaries. The challenge facing America is the same as that which faces China, Mexico, India, and every nation – and every citizen – in-between.

But as I said, the challenge today is similar in concept. Like the commitment we made in the 1980s, today we must again "expand the menu of options." And again, as in the 1980s, a greater number of technological options will make future policy decisions much easier.

Since the time global warming appeared on the world's agenda, the two predominant options for reducing greenhouse gases have been to:

- use energy more efficiently, and
- increase our use of low-carbon and carbon-free fuels (for example through the greater use of renewable technologies).

I'm here tonight to tell you that we are not going to step away from either of those options. Alternative energy sources like solar, wind, biomass, and geothermal will have a growing role in our energy portfolio. We will have to learn to use energy more efficiently.

But there is an extremely important third option to our climate change strategy. I believe we can – and should – look to new coal-based technologies and new ways to capture and control the release of carbon. This should become another option in our "menu" for future greenhouse gas controls.

At the Department of Energy, we believe it is possible to develop a virtually pollution-free, coal-fired power plant within the next 15 years or so. No air pollutants. No landfill wastes. A plant that doubles the amount of electricity we can currently extract from coal and produces other commercial products as well.

(As a matter of fact, the technology being developed over in Kingsport -- one of the major successes from the 40 projects -- might be the model on which we will base our liquid fuels and chemical production.)

We call the concept "the Vision 21 EnergyPlex," and we've increased research and development funding on this plan to $29 million dollars in FY 2000.

"Vision 21" starts us down the final path of making coal part of tomorrow's solution. But it doesn't get us all the way there. To do that, I believe we need to add to the clean coal "menu" a new commitment to develop carbon sequestration – the potential to capture and dispose of carbon.

Coupled with higher-efficiency power plants, carbon sequestration may offer a way to achieve truly massive reductions in carbon levels at relatively low costs. And the federal government is backing this technology as a possible real option to the problem: working with the Departments of Interior, Agriculture, EPA, and others.

Carbon sequestration offers us one major advantage over other climate change options: it doesn't require wholesale changes in the world's energy infrastructure.

The major advantage of our world's present energy system – one based largely on fossil fuels – is quite simply that it works. It is relatively low cost. It uses low-cost and globally abundant resources.

But in the United States and many other countries, our energy infrastructure didn't come easy. It represents a huge capital investment – an architecture that will not be discarded overnight. With carbon sequestration, it won't have to.

So let's put Kyoto aside, and look at the really long term – 30, 50 or 70 years into the future. Carbon sequestration could offer one of the best options for reducing the buildup of greenhouse gases, not only in this country but in China, India and elsewhere.

Sequestration could be the single most important factor in the truly long-range future of coal and, in fact, for all of fossil fuels. It makes coal part of the energy answer, rather than part of the environmental problem.

We're on the drawing board today on carbon sequestration -- just as we were two decades ago with clean coal technologies. Now is the time that partnerships begin to form. Now is the time when we look for the best ideas and worry about proprietary interests later.

That is the third reason I wanted to speak to this group in particular.

You understand how to make partnerships work. Fifteen years ago, the Clean Coal Technology Program began as a partnership between government and industry. It was focused on a regional problem. Today, there is a new paradigm for collaboration. It must be global – because the challenge is global.

That is why I am here this evening to tell you that I have directed our staff at the Department of Energy to develop a long-range program that will encourage carbon sequestration research partnerships on a global basis. We will aggressively seek out new government-to-government agreements in carbon sequestration research. We will expand our industry and academic research into new concepts.

And in the future, when we offer Department of Energy cost-sharing for new sequestration projects, we will structure our competitions to encourage not only teaming between U.S. government, industry and academia, but teaming that extends across international borders.

We want to uncover the best ideas – no matter where they originate. It is too important to the future of coal – and to the long-term health and well being of the citizens of this planet – to do anything less.

Those of you in this room can expand the "menu of options" again. That is my challenge to you this evening. I make it because I am convinced that if we are successful, we can make the world's difficult policy decisions on controlling greenhouse gases easier and less expensive. And by doing so, we can help the community of nations to be better off.

LUNCHEON

Clean Coal Technologies–A Rational Roadmap to Reliability

CLEAN COAL TECHNOLOGIES—A RATIONAL ROADMAP TO RELIABILITY

Irl F. Engelhardt
Chairman and CEO
Peabody Group
St. Louis, Missouri, USA

ABSTRACT

It is imperative that government and industry come to agreement this year on a roadmap for development and deployment of cleaner and more efficient coal conversion technologies. In the absence of a joint vision for coal-based generation, energy costs will rise in the United States and abroad making the economic, environmental and social aspirations of many nations far less attainable.

REMARKS

Thank you and good afternoon everyone.

I appreciate this opportunity to address a group so obviously devoted to the future of the electricity and coal industries. I share your belief that the deployment of more efficient, cleaner technologies to use coal to generate electricity is a critical issue to the electricity industry in the United States and to the U.S. economy.

Mother Nature has blessed the United States with an enormous economic advantage in the form of coal resources. The U.S. has used that resource wisely to generate low-cost electricity that helps create economic prosperity and a better quality of life. Coal is truly America's Fuel, and coal offers the U.S. an energy source that provides the perfect balance to satisfy environmental, economic and human needs.

Critics from the environmental community argue that the use of coal should be eliminated. They ignore the impact of their recommendations on the economy and on U.S. jobs as they attempt to "regulate" the earth's climate. Let's ignore for a moment the practicality of regulating the earth's climate. The key issue is "balance". We must balance the satisfaction of environmental needs with the satisfaction of economic and human needs.

In the 1860's when John Muir, one of our country's first environmentalists, reached the California coast, he said America had reached its limit – its last frontier. If John Muir could travel to Silicon Valley today, he would see that there are many new frontiers…technological frontiers that America needs to explore.

Clean coal technology is one of those frontiers, and I applaud the efforts of those of you who are striving to improve the conversion of coal into clean, low-cost electricity. You are contributing to a better quality of life.

Yet, your contributions are under attack as never before.

Coal is under threat from the environmental community, with the aid of public indifference.

Coal is threatened by the media, which ignores the successes of our reclamation and clean air initiatives while reminding the public of the past when modern technology and practices did not exist.

And, many in the industry believe that coal is threatened by an Administration in Washington whose apparent aim is to eliminate coal from our energy arsenal at all costs.

The Kyoto Protocol and the successive Clean Air Act regulatory proposals of the Environmental Protection Agency combine to form a potential staircase to oblivion for electricity fueled by coal. And yet, the consequences to the security of energy supplies, to satisfaction of future electricity demand and to maintaining economic growth all seem to be studiously ignored by the U.S. Administration.

This apparent state of siege against coal presents some basic questions.

The question for all of us in this room is whether we will support the resurrection of the program to stimulate clean coal technology or preside over the demise of that program?

For those representing our government, some simple questions have to be asked. Where is the Department of Energy in pleading the case for fuel diversity and energy security? The Department of Energy is charged with ensuring adequate and affordable energy, yet many believe that it is not defending America's most abundant energy resource. Has DOE become a subsidiary agency to the EPA or will it ensure the proper balance in the Administration's policy debates?

Will the Departments of Commerce and the Treasury fulfill their missions to stimulate economic development and growth, or will they burst the bubble of economic prosperity by supporting an international treaty and regulatory actions that many experts agree will have the opposite effect?

Will environmental policy become **the** central organizing principle of government, or will the economic prosperity and standards of living of 260 million Americans hold equal moral standing?

Will the academic community insist on solid, peer-reviewed science, or will the attraction of future research opportunities silence their questions?

Questions have to be asked of industry as well. Will the coal and electricity industries be part of the solution and actively promote new technologies, or will we stick our collective heads in the sand?

Clearly these questions are complex and defy simple answers. I have asked the questions to stimulate your questions and comments at the end of my remarks. To begin the debate; however, I will offer a **plea** and a **vision** for clean coal technology.

My **plea** is that those in government and in the private sector agree **this year** on a roadmap for development and deployment of the technologies for more efficient and cleaner electricity from coal.

Why this urgency?

Last fall, the Energy Information Administration (EIA) presented the results of a study of the impact of the Kyoto Protocol on U.S. electricity generation. (HOLD UP COPY OF SUMMARY).

The EIA study suggests that by 2020, coal's share of the electricity market will fall from its current level of 56 percent to between zero and 15 percent, if the U.S. implements the Kyoto Protocol. The study also suggests that generation from natural gas will increase three-fold and that natural gas prices will jump by 227 percent, from $2.64/MMBTU in 1998 to $8.63/MMBTU in 2010.

The urgency is real. Electricity demand is growing and reserve margins are shrinking. Additional capacity will be needed to meet increased electricity demand and replace older units. The possibility of an artificial timetable for carbon emission reduction only adds to that urgency.

The International Energy Agency projects that world demand for electricity will increase 70% between 2000 and 2020. To meet this increased demand, one new 1000-megawatt power plant will have to be built every 5.6 days, on average, from now until then.

How the world's financial and energy resources will be stretched to fuel those power plants depends very much upon whether efficient clean coal technologies will be available as part of the mix.

The demand for electricity is real, yet its availability is not secure. And, that is where you come in.

Our country – and the world - needs a roadmap that explains how we will satisfy the increasing demand for electricity in a way that is balanced with the impact on the economy and the environment. Policy makers and private sector investors alike need to know what it will take. And, they need to understand the opportunities...and the consequences... of success or failure in following such a roadmap.

I make this plea because I believe such a roadmap is critical to the maintenance of economic stability and growth in the U.S.

In this country, coal remains the largest and is among the least expensive sources of electricity generation. Last year, the average cost of electricity generation from coal was one half the average cost of electricity from natural gas. So, simply replacing coal with gas for generation means effectively doubling the cost of electricity.

There are also serious questions that must be answered about the availability of gas supplies to satisfy increasing needs for electricity generation. And, I believe we must provide the public with the true story of the impact of gas price increases on home heating bills and home electricity bills. The point is that switching to natural gas to generate electricity has serious impacts on the U.S. economy and U.S. citizens. It is difficult to say that economic or human needs will be satisfied by the switch.

The need for new coal technologies that you are developing exists throughout the world. The EIA projects that world-wide coal consumption will increase by 40% from 2000 to 2020. We have an enormous opportunity to reduce CO2 and other emissions if we use the new coal generating technology that we are discussing! And, consider the millions of lives that will experience a better quality of life as their homes are electrified and stronger economies provide them with better jobs. That is our goal – a better environment balanced with strong economies and a better quality of life.

So my **plea** is straightforward. Let's come to agreement on a roadmap, let's develop the plan that will make the best coal based generating technologies available both here and abroad. And let's do it this year.

The **vision** I have in mind is also very simple...at least in concept.

Our vision should be to design and deploy technologies that will convert coal to electricity with efficiencies <u>greater than 55 percent</u> and with <u>zero emissions</u> of criteria* pollutants.

If this vision is unattainable...or if it is understated, you will have to tell us. Once the goal is set and the roadmap is agreed to, however, the real test begins.

Will we have the will and the commitment to follow the progressive path that is laid out?

The answer to that question remains to be seen. Much like the rhetorical questions I posed earlier, the answer depends upon whether those of you with the knowledge of the technological possibilities can give the rest of us the vision to make it happen.

A clear and achievable technological vision would help us answer many of those questions.

The vision of our goal and a definitive roadmap to the goal will lend comfort to policy makers, the public and the media that the many benefits of coal can be balanced with the needs of the environment.

The roadmap will allow our nation to use its **natural** advantage – our most abundant fuel resource - in a very competitive world economy.

And, the roadmap will make new technology available to other nations as they satisfy their citizen's needs for electricity while using their indigenous fuels.

The John Muirs of this world might say that coal has reached its last frontier. I disagree. I believe we are at the gateway of a new frontier. You are the explorers and the mapmakers of this frontier. You are the experts, the source of the roadmap. Your work has never been so important or so urgent as it is now.

Thank you for your kind attention. I wish you good luck and urge great speed in your endeavors.

(* NOTE: Criteria pollutants include particulates, SO2, NOx, and CO, but do not include CO2)

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